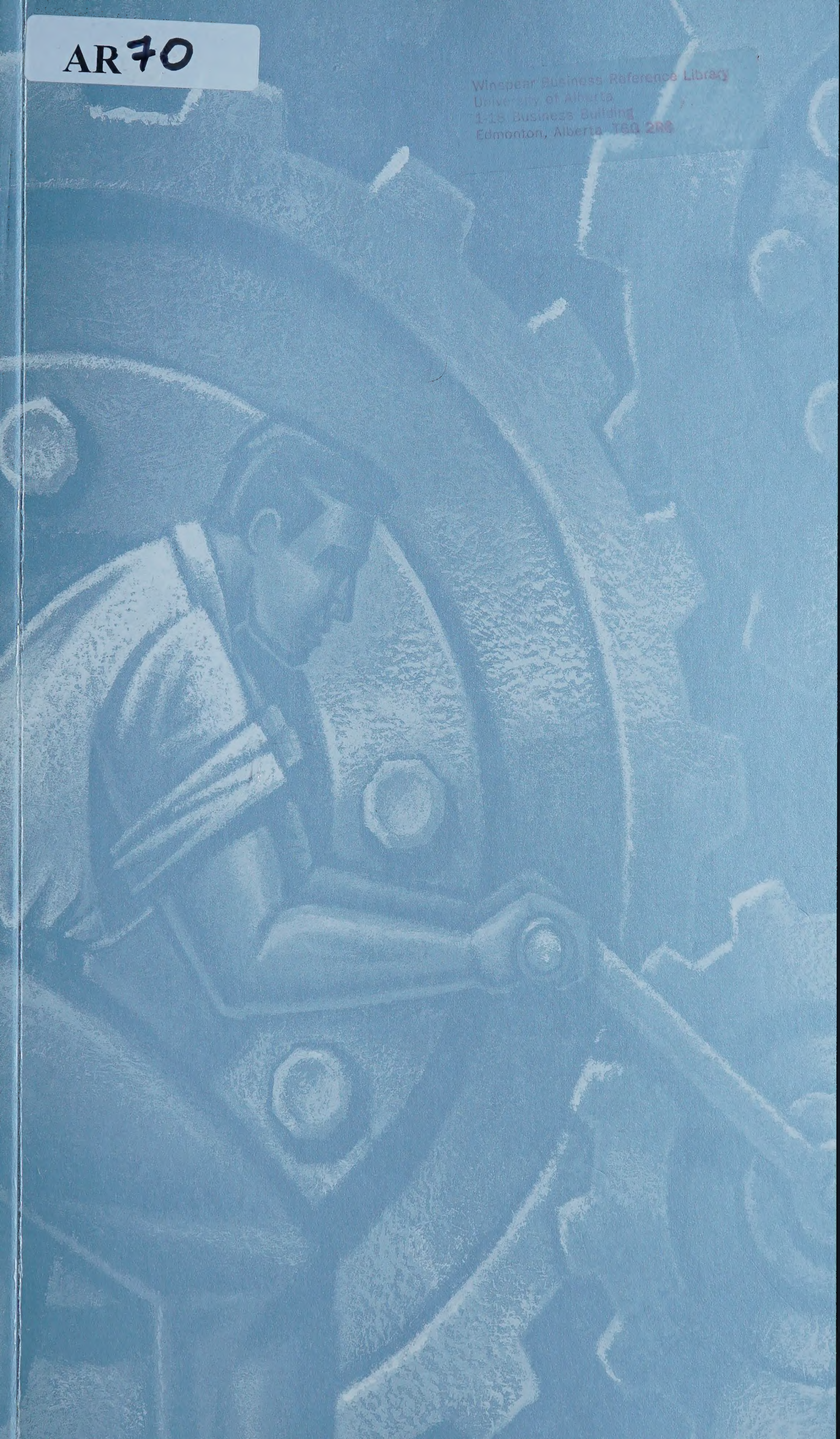


DYNAMIC OIL & GAS, INC.

2002
Annual Report

Dynamic Oil & Gas, Inc. is a rapidly growing TSE and NASDAQ small-cap, resource-based energy company with a strong position in Western Canada.

Natural gas and natural gas liquids make up over ninety-nine percent of the Company's proven reserve base.

Dynamic has a strong commitment to this secure, clean and abundant source of energy.

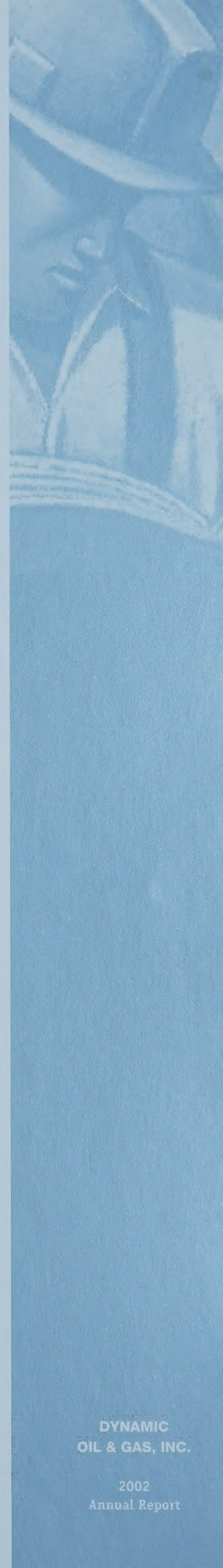
2002 HIGHLIGHTS

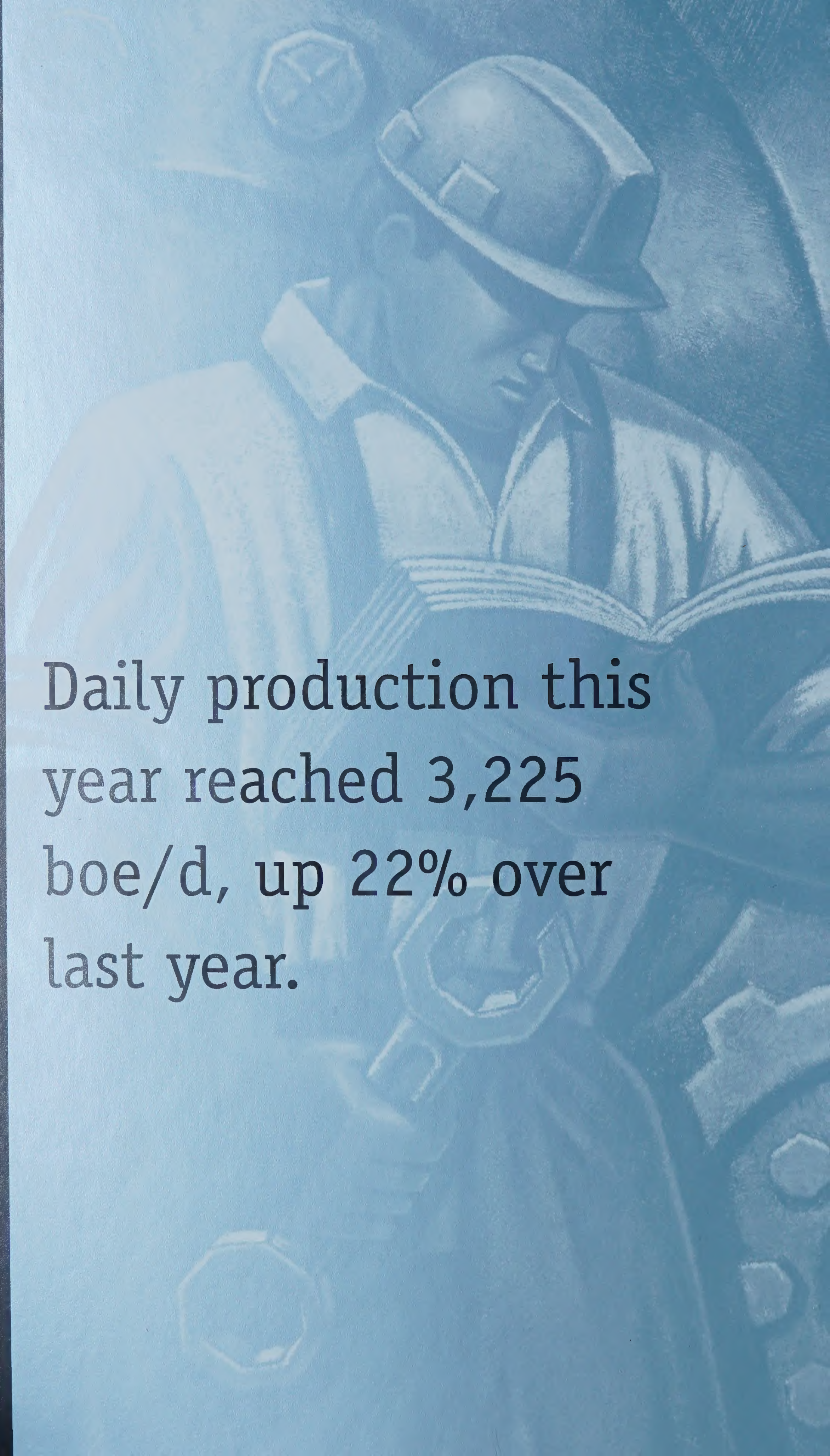
	2002	2001	Change	% Change
Operations				
Daily production				
Natural gas (mcf/d)	**15,107**	12,486	2,621	21
NGL's (bbls/d)	**631**	530	101	19
Oil (bbls/d)	**76**	33	43	130
All products (boe/d)	**3,225**	2,644	581	22
Total annual production (mboe)	**1,177**	965	212	22
Prices – weighted average				
Natural gas ($/mcf)	**3.81**	6.22	(2.41)	(39)
NGL's ($/bbl)	**19.30**	30.64	(11.34)	(37)
Oil ($/bbl)	**34.33**	43.60	(9.27)	(21)
Equivalent ($/boe)	**22.26**	35.66	(13.40)	(38)
Corporate netback ($/boe)	**12.08**	21.27	(9.19)	(43)
Reserves				
Natural gas (mmcf)	**44,740**	45,797	(1,057)	(2)
NGL's and oil (mbbls)	**2,458**	1,541	917	60
Total (mboe)	**9,915**	9,174	741	8
Undeveloped land				
Net acres	**69,162**	67,871	1,291	2
Financial ($ thousands)				
Gross revenues	**26,402**	34,463	(8,061)	(23)
Funds flow from operations	**11,337**	18,168	(6,831)	(37)
Per common share	**0.55**	0.91	(0.36)	(38)
EBITDA*	**7,226**	17,671	(10,445)	(59)
Per common share	**0.35**	0.89	(0.54)	(61)
Net (loss) earnings	**(3,519)**	9,714	(13,233)	(136)
Per common share	**(0.17)**	0.49	(0.66)	(135)
Capital expenditures	**22,111**	11,582	10,529	91
Operating loan	**14,750**	–	14,750	–
Common shares outstanding				
Basic	**20,365,031**	19,937,585	427,446	2
Diluted	**20,466,543**	20,444,979	21,564	–

** EBITDA is earnings before interest, taxes, amortization and depletion. EBITDA is a non-GAAP measure that does not have standardized meaning as prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies.*

ABBREVIATIONS

bbl or bbls	barrel or barrels	mcf	thousand cubic feet
bbls/d	barrels per day	mcf/d	thousand cubic feet per day
mbbl	thousand barrels	mmcf	million cubic feet
boe	barrels of oil equivalent (6 mcf = 1 bbl)	mmcf/d	million cubic feet per day
boe/d	barrels of oil equivalent per day	NGL's	natural gas liquids
mboe	thousand barrels of oil equivalent		





Daily production this year reached 3,225 boe/d, up 22% over last year.

LETTER FROM THE PRESIDENT

A few weeks ago, I had an opportunity to speak to the Canadian Association of Petroleum Producers (CAPP) in Calgary, Alberta. The Association represents approximately ninety-five percent of the oil and gas exploration and production companies in Canada. Larger producers, in their presentations, emphasized slow and deliberate growth through low-risk projects like the Alberta tar sands. Junior producers talked about the need to grow rapidly by identifying new oil and natural gas reserves.

The theme of my CAPP presentations was the rapid growth that Dynamic has planned through identification of new reserves. Plans for the discovery of new oil reserves at our property in St. Albert, Alberta and plans for the discovery of new natural gas reserves at our property in Orion, British Columbia.

The theme of my CAPP presentations was the rapid growth that Dynamic has planned through identification of new reserves.

Year in review...

As we embarked on fiscal 2002, our focus was to significantly enhance our natural gas reserve base. We intended to increase natural gas reserves and productivity from our Peavey/Morinville property in Alberta. We set out to increase our interest in St. Albert, our core property – a property that currently produces mostly natural gas and natural gas liquids. We planned to follow up on last year's early natural gas successes at our newest property, Halkirk, Alberta. We intended to further explore for natural gas at our Orion property in northeast British Columbia. We planned to do all this and maintain a manageable level of debt.

As the year progressed it became apparent that our plans, at least at our Peavey/Morinville property, were not to be rewarded. We began to experience much higher decline rates and smaller natural gas reserves than expected. By year-end, it was clear that the recorded value of the property on our corporate balance sheet was excessive and a write-down would be necessary. This was a bitter pill to swallow but there was no choice. It was a non-cash write-down that resulted in significant negative effect on our fiscal earnings picture but the Company's cash flows remained strong due to solid gas prices and increasing productivity.

Our fiscal 2002 plans at St. Albert were much more rewarding. On June 29, 2001, I announced the purchase by Dynamic and partners of the controlling interest in the property from Fletcher Challenge Oil and Gas Inc., a part of Apache Canada Ltd. Dynamic's previous share of the natural gas and oil interests in the property of 50% and 25%, respectively, increased to 75% across the board.

The increase in interest at St. Albert contributed significantly to our fiscal 2002 daily production averages of natural gas and natural gas liquids. Full-year daily production averages increased corporately over fiscal 2001 by 581 boe/d or 22%, to 3,225 boe/d. St. Albert made up 94% of this increase.

At Halkirk, our 2002 efforts were also rewarded. We began the year with two proved, non-producing natural gas wells and exited the year with six proved, producing natural gas wells. Daily average production for fiscal 2002 increased by 138 boe/d over fiscal 2001, with a year-end exit rate of 252 boe/d.

Plans for Orion progressed steadfastly during fiscal 2002 and on June 10, 2002 our hard work was rewarded. I announced we had struck a farmout deal with a large independent Canadian oil and gas company active in the Greater Sierra area of northeastern British Columbia. Orion is recognized as part of the Greater Sierra area, a potential new world-class discovery that could contain several trillion cubic feet of natural gas reserves. Drilling on our lands will initially target sweet, dry natural gas in a regional, reef-carbonate formation known as the Jean Marie. Additional gas and oil targets are also known to exist in the area.

The farmout deal stipulates that drilling of the first well at Orion will take place this summer. If full terms of the farmout deal are met, up to three additional wells could be drilled over the next two years or sooner. That would be an estimated total of $8 million spent evaluating our lands. Dynamic would retain an overall average working interest of 32%. Assuming we continue to be successful and our investment returns are rewarding, Dynamic staff estimates full development of Orion, including additional wells and pipelines could take three years or so and cost $40 million gross.

In summary, fiscal 2002 was a stage-setting year. Had results at Peavey/Morinville worked out for the best, our plans to significantly grow natural gas reserves would have fully been met. Overall, corporate reserves increased by 8%, with St. Albert being the main source of the increase. Daily production rates of natural gas and natural gas liquids, however, grew significantly. The daily production average rate increased by 1,046 boe/d or 39% over fiscal 2001, to exit the year at 3,725 boe/d.

A look ahead...

The Board of Directors has approved a capital expenditures and exploration expense budget for fiscal 2003 of $18.1 million. Exploratory drilling comprises over 45% and development drilling makes up over 31% of the budget. Nearly 80% of it is to be spent on natural gas-related projects. We expect the budget

to be funded from our operating cash flows. The Orion farmout deal was announced after the fiscal 2003 budget, so $5.3 million originally budgeted for Orion may now be freed up for new projects already on our drawing board. Replacement projects will be announced, as warranted.

It's clear how much the St. Albert property contributed to our stats for fiscal 2002 and we firmly believe in the property's continuing importance. For example, prior to owning any interest in the St. Albert property, we always believed in its potential to contain substantial new oil reserves. While natural gas is the primary corporate target, we now own 75% of the mineral rights to prospective oil zones at St. Albert.

On April 3, 2002, I announced results of our first new oil well at St. Albert. In our fiscal 2003 budget, we include a six to seven-well evaluation program to test as many as six Devonian oil zones – all zones having tested or produced in the area previously. To reduce environmental impact and keep costs down we will make use of existing well bores and advanced directional drilling techniques wherever possible.

Final thoughts...

With the terrible events in mind of September 11, we appreciate more and more the benefits of a strong continental energy industry. Natural gas prices have remained sound, not falling back to lower levels as many predicted and Dynamic's long-stated goal to discover safe sources of natural gas is increasingly vital. Clean burning natural gas is the energy choice for today and the future.

Opportunity is Dynamic's focus for interesting times ahead.

We live in a changing world and I am often reminded of the old Chinese curse, "may you live in interesting times". Of course, the Chinese character for 'interesting' can mean 'dangerous' but more importantly, it can also mean 'opportunity'. Opportunity is Dynamic's focus for interesting times ahead.

As we close fiscal 2002 and look forward to next year, I sincerely invite shareholders to closely examine our Company's fundamentals and am pleased to present them to you in this report. Join me as we search for even more opportunities in the next twelve months and beyond.

Wayne Babcock

Wayne J. Babcock,
President & Chief Executive Officer

We will continue to capitalize on the experience and technical strengths of our employees and key consultants to develop and explore our growing portfolio of properties.

REVIEW OF OPERATIONS

Dynamic's growth has been founded on a strategy of building a risk portfolio blended with lower-risk development projects and higher-risk exploration projects. In recent years, Dynamic has focused its energies on a core group of properties with lower-risk characteristics in central Alberta. These properties generally allow for shallow-to-medium drill depths and multi-zone natural gas targets. At the same time, the Company has established significant land positions in northeast and southwest British Columbia and in the southern Alberta foothills. These properties are of a higher-risk, higher-reward nature and afford pure exploration opportunities.

Dynamic will continue to capitalize on the experience and technical strengths of its employees and key consultants to develop and explore its growing portfolio of properties. The Company is alert to the opportunity for creating shareholder value through forward-looking projects.

Drilling Summary

The Company operated thirteen of fourteen wells drilled during fiscal 2002, resulting in seven natural gas wells, two potential natural gas wells, one oil well and four dry holes achieving an overall success rate of 75%. In addition, Dynamic operated five re-entry/workover operations on previously suspended or low productivity wells in St. Albert that resulted in four natural gas wells and one unsuccessful attempt. Of the successful wells, two were new pool discoveries.

Drilling Activity

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Gas completions	**7**	**6.1**	11	8.7	4	3.6
Potential/suspended gas wells	**2**	**1.4**	3	2.0	–	–
Oil completions	**1**	**0.7**	1	0.9	–	–
Dry and abandoned	**4**	**2.8**	2	1.9	2	1.2
Total	**14**	**11.0**	17	12.5	6	4.8
Success rate		**75%**		85%		75%

Land Summary

In Alberta, Dynamic has established significant blocks of developed and undeveloped land in four areas: St. Albert; Peavey/Morinville; Halkirk and Quirk Creek. In British Columbia, it has established large blocks of undeveloped land at Orion and Fraser Valley. Orion, located in the northeast sector of the province, is an active core area for the Company, while Fraser Valley in the southwest corner of the province is currently inactive.

Dynamic's total land holdings increased during the year by 23,900 gross acres or 19%, to 150,171 gross acres. These additions were spread among four properties: Halkirk, Peavey/Morinville, St. Albert and Quirk Creek, and two other properties in central Alberta. Dynamic will continue to diversify and strengthen its land holdings in fiscal 2003.


NORTHWEST TERRITORIES
YUKON
Whitehorse
Watson
Telegraph Creek
Summit Lake
Fort Nelson
ORION
Fort Simpson
Yellowknife
Great Slave Lake
Fort Resolution
Meander River
Fort Fitzgerald
Uranium
Lake Athabasca
BRITISH COLUMBIA
Williston Lake
ALBERTA
Fort McMurray
Hazelton
Prince Rupert
Kitimat
Fort St. John
Dawson Creek
Peace River
PEAVEY/MORINVILLE
Grande Prairie
Valleyview
WESTLOCK
Vanderhoof
Prince George
Whitecourt
St. Paul
Meadow Lake
Bella Coola
Hinton
Jasper
Edmonton
North Battleford
ST. ALBERT
Red Deer
HALKIRK
FRASER VALLEY
Revelstoke
Kamloops
Calgary
QUIRK CREEK
Brooks
Swift Current
Medicine Hat
Vancouver Island
Vancouver
PACIFIC OCEAN
Victoria
Cranbrook
Lethbridge
Milk River
Shelby
Seattle
Spokane
Tacoma
Olympia
WASHINGTON
Yakima
Great Falls
Missoula
Helena
MONTANA
Portland
Salem
Butte
Billings
Eugene
OREGON
IDAHO
Boise
Idaho Falls
Jackson
Twin Falls
Rock Springs
CALIFORNIA
NEVADA
UTAH

Land Holdings (acres)

[illegible]

Plans for 2003

[illegible]

St. Albert, Alberta

St. Albert/Big Lake is located in central Alberta near the City of Edmonton. The area is prospective for remaining recoverable oil from six established oil pools within the Leduc (D-3), Nisku (D-2) and Wabamun (D-1) formations. These formations are underlying multiple pools of stacked, natural gas-bearing sandstones of Cretaceous age. Dynamic owns an average working interest of 66% in 15,350 gross acres of land including 6,293 gross undeveloped acres. In addition, the Company also owns an average 66% share of various overriding royalty interests associated with an additional 4,729 gross acres.

Announced on June 29, 2001 and effective April 1, 2001, Dynamic increased its interest at St. Albert under a Purchase and Sale Agreement with Fletcher Challenge Oil & Gas, Inc. ("Fletcher"). Under the agreement, Dynamic acquired 50% of Fletcher's interest in the shallow gas wells and facilities and 67% of Fletcher's interest in the oil wells and facilities, and assumed the duties of Operator effective June 30, 2001.

As of the end of fiscal 2002, Dynamic owned and operated a 75% working interest in fourteen producing gas wells, six producing oil wells and various working interests ranging between 25% and 83% in four other producing gas wells, five suspended potential gas wells and six additional wells awaiting further evaluation. The Company owns a 25% interest in a ten-mile sales gas pipeline system and in a significant gas processing facility capable of processing 15 mmcf/d of sour gas and 15 mmcf/d of sweet gas. Further, it owns a 75% interest in an oil battery capable of processing 2,400 boe/d.

In fiscal 2002, Dynamic conducted re-entry/workover operations on five previously suspended or low production wells resulting in four natural gas wells and one unsuccessful attempt. Over the past three years, exploration and development at St. Albert focused on shallow gas prospects until Dynamic pursued a new oil target within the established Devonian-aged pools by drilling a successful Nisku (D-2) oil well in February, 2002. By the end of fiscal 2002, the well had averaged 89 boe/d over a 57-day production period.

Dynamic increased its average daily production rates at St. Albert in fiscal 2002 by 547 boe/d or 25%, to 2,717 boe/d over fiscal 2001. The increase was primarily due to the acquisition of additional interest from Fletcher. Production increases at year-end came as a result of a modification to a sour compressor facility and the successful workover of five previously suspended or low producing wells. The Company exited the year producing 3,224 boe/d from the field. At the close of fiscal 2002, proved natural gas, natural gas liquids and oil reserves were independently estimated at 7,201 mboe and risked probable reserves were estimated at 338 mboe.

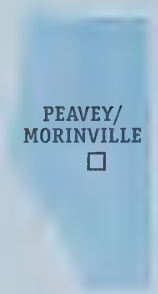
Historically, the property has produced in excess of 23 million barrels of oil and 83 bcf of raw gas. Prospectively, Dynamic has identified several potential targets for additional oil and gas recovery on the property. The Company has budgeted eight new wells at St. Albert in fiscal 2003, six targeting the remaining oil potential in the established oil pools and two wells targeting new gas reserves.

MAP LEGEND

Location	Suspended
Service or Drain	Oil
Gas	Dry & Abandoned
Suspended Oil	Abandoned Oil
Suspended Gas	Abandoned Gas
Abandoned Service	Injection

Dynamic Land January 2002

Peavey/Morinville, Alberta

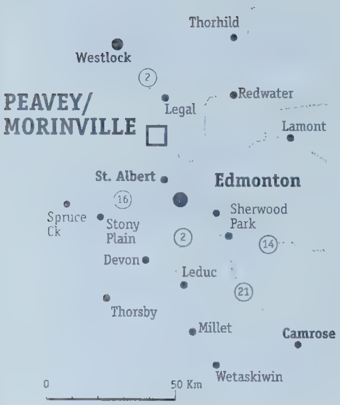


Property Description

Peavey/Morinville is approximately nineteen kilometres north of the City of Edmonton. The area is prospective for multiple oil and natural gas-bearing sandstones of Cretaceous age. These sands are stratigraphically controlled and structurally draped over highs in the Leduc reef. Presently, the Company owns an average 66% working interest in approximately twenty-six square kilometres of 3-D seismic data and 13,994 gross acres of land including 6,630 gross acres of undeveloped land.

Wells and Facilities

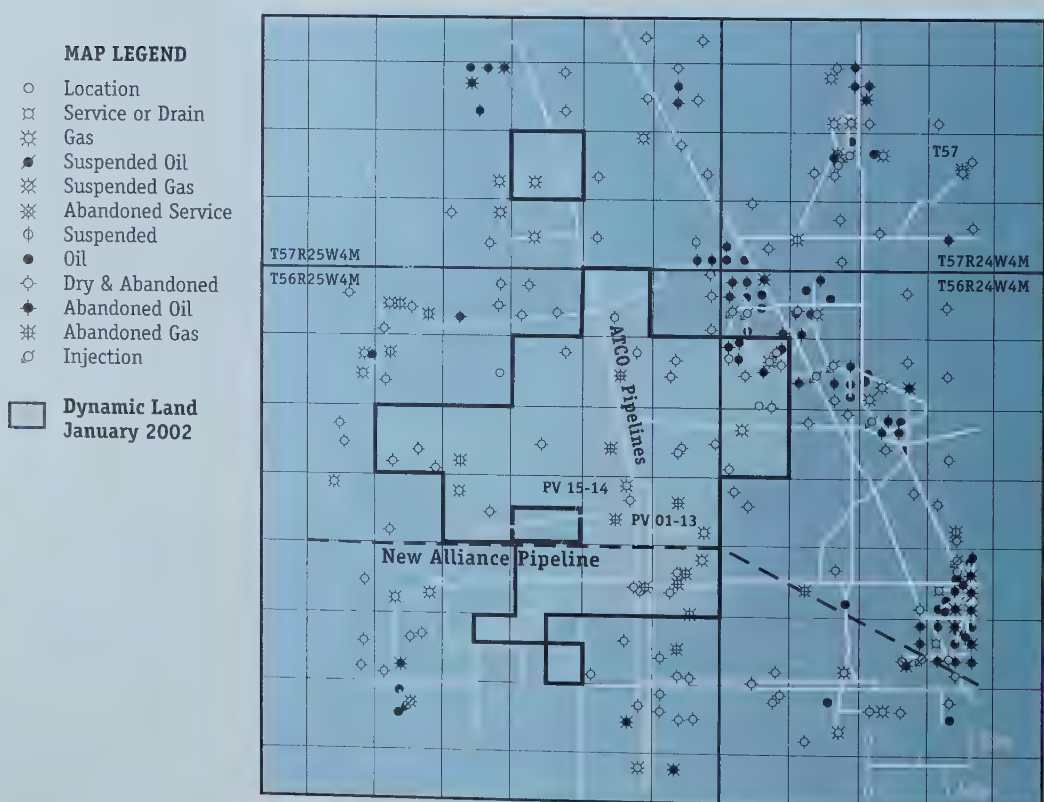
Dynamic is the Operator and holds an average working interest of 77% in seven producing gas wells in this area and 100% working interest in a 5.5 mmcf/d, compression/dehydrator facility. At the end of fiscal 2002, approximately 0.8 mmcf/d of third party production was being processed through this facility. Dynamic holds various working interests ranging between 35% and 96% in eleven shut-in or suspended gas wells, one potential oil well and two wells awaiting abandonment.



Production and Reserves

The average annual daily production rate from the property remained steady at close to 290 boe/d between fiscals 2001 and 2002 . However, due to the unexpected influx of water, the year-end exit rate decreased by 269 boe/d or 62%, to 165 boe/d from fiscal 2001. As a result, the Company's independent estimate of proved reserves was revised downward by 1,143 mboe or 61%, to 742 mboe from fiscal 2001.

Presently, the Company is examining ways to maximize the value in this property. The property contains a substantial network of pipelines including a gas compression facility, eleven shut-in or suspended gas wells, 6,630 gross acres of undeveloped land and is covered by approximately twenty-six square kilometres of 3-D seismic data. Among the possibilities, the Company is considering the property as prospective for coal bed methane development.



Halkirk Area, Alberta

Property Description

Halkirk is located approximately one hundred and seventy kilometres northeast of the City of Calgary, Alberta. The area is prospective for the development of three sweet gas horizons: the Belly River, Viking, and Hackett formations. The primary target for reserves is the Viking "C" sand with an average net pay thickness of 5.3 metres. The area is also close to existing gas processing facilities. Dynamic owns an average 95% working interest in 7,040 gross acres of land including 3,200 gross undeveloped acres. Dynamic increased its land holdings in the area by 2,880 gross acres during fiscal 2002.

Wells and Facilities

Dynamic is the Operator and owns an average working interest of 92% in seven natural gas wells on the property including six producing and one capped gas well. In fiscal 2002, Dynamic drilled five of the seven wells resulting in four gas wells and one capped gas well. During the year, six of the wells were connected by pipeline to a third-party gas processing facility in the area.

Production and Reserves

Production from the field began in late October 2001 and closed out fiscal 2002 averaging 252 boe/d. At the close of fiscal 2002, independent proved natural gas reserves were estimated at 595 mboe and risked probable reserves were estimated at 313 mboe.

Plans for 2003

The Viking "C" formation provides access to lower-risk natural gas reserves that the Company believes to be long-life reserves. Eight additional drilling targets have been identified on the existing land block with four of the eight locations planned for fiscal 2003.

MAP LEGEND

- Location
- Service or Drain
- Gas
- Suspended Oil
- Suspended Gas
- Abandoned Service
- Suspended
- Oil
- Dry & Abandoned
- Abandoned Oil
- Abandoned Gas
- Injection

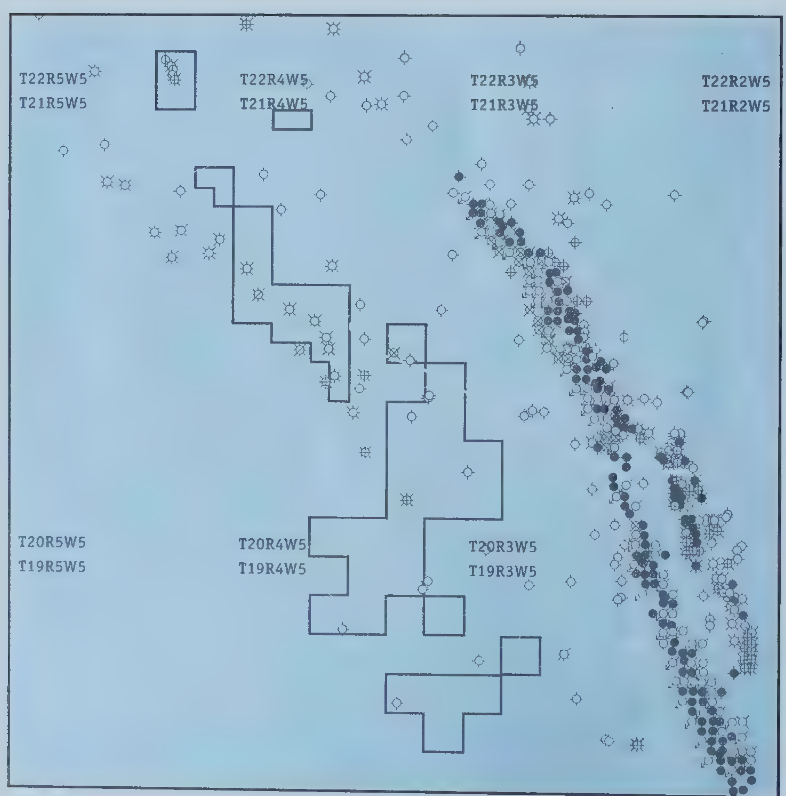
Dynamic Land January 2002

Quirk Creek, Alberta

Quirk Creek is located in the foothills of southern Alberta approximately forty-two kilometres southwest of Calgary. The Company is targeting new reserves of sweet natural gas in a thick section of sandstones in the Cretaceous Blairmore Group at depths up to 1,800 metres. The gas is contained within sediments that are highly fractured due to the presence of northwest/southeast trending thrust faults that run through the area. At the end of fiscal 2002, Dynamic held a 50% interest in 20,960 gross acres of undeveloped land.

Under a Farmout and Option Agreement with a large integrated oil and gas company, Dynamic and another junior company participated in drilling one exploration well at Quirk Creek in March 2002. Under the agreement, the Company earned a 50% interest in 1,280 gross acres of land, plus an option to drill up to three additional wells in the area to earn 50% in another 7,680 gross acres. The well was drilled to a depth of 1,825 metres using air drilling techniques. Several shows of gas were reported during the drilling operation, although no commercial quantities of gas were encountered or indicated on logs. Post-drilling analysis of the well indicates the anticipated rock-fractures were encountered, however, these fractures were predominately healed or closed at that location.

In addition to considering its options under the Farmout and Option Agreement, Dynamic has identified two re-entry opportunities on company-owned lands that could provide a more cost-effective way to further test this thick Blairmore Group of sediments for commercial quantities of sweet natural gas. Re-entry work is planned in fiscal 2003.



MAP LEGEND

Location
Service or Drain
Gas
Suspended Oil
Suspended Gas
Abandoned Service
Suspended
Oil
Dry & Abandoned
Abandoned Oil
Abandoned Gas
Injection

Dynamic Land January 2002

Other Alberta Properties

Other producing properties outside of St. Albert, Peavey/Morinville and Halkirk comprise 10,412 gross acres and 8,987 net acres for an average working interest of 86%. They produced 29 mboe of natural gas and oil during fiscal 2002, representing approximately 2% of the Company's total annual production. This production was generated from six properties: Alexander; Elmore; Rapdan; Simonette; Stanmore; and Westlock. The majority of this production was natural gas from Stanmore and Westlock, two single-well properties in Alberta.

Orion, NE British Columbia

Property Description

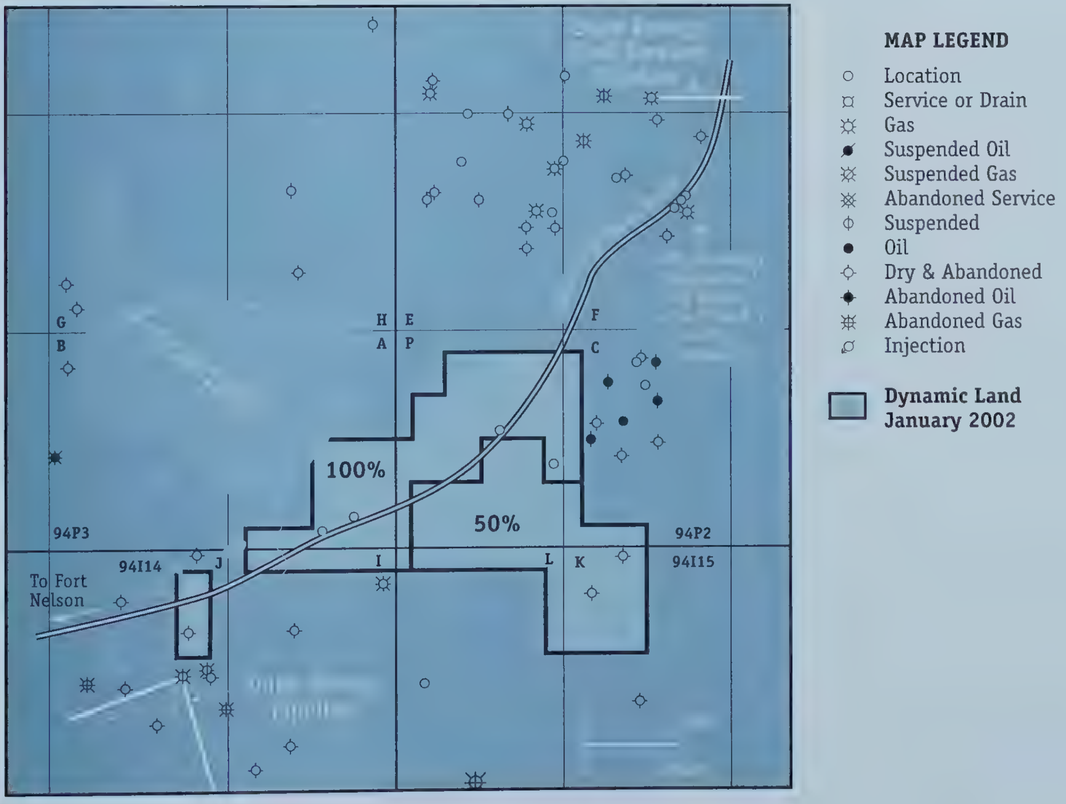
Orion is strategically located between the Sierra and Helmet natural gas fields. Located near Kotcho Lake, the acreage is approximately fifty-six kilometres west of the Alberta border and one hundred and twelve kilometres south of the Northwest Territories. The property is dissected by the Sierra Yoyo Desan Road, which provides year-round access for drilling operations. The Jean Marie formation is considered to be a regional platform carbonate with extensive patch-reef development at sub-surface depths of between 1,000 and 1,400 metres. The formation averages one hundred and ninety metres thick and is draped over deep-seated substructures. A prolific open fracture network enhances reservoir permeability. As at the end of fiscal 2002, Dynamic held an average working interest of 78% in 30,003 gross acres of undeveloped land.

Wells and Facilities

Dynamic owns a working interest of 100% in one suspended potential natural gas well. In fiscal 2002, Dynamic perforated and tested the Bluesky and Wabamun formations in the well. It is currently suspended as a potential natural gas well pending further evaluation and development of a sales pipeline system. The property is located at the termination of two major pipeline systems. The Duke Energy Pipeline System is located seven kilometres south of the property and connects to Fort Nelson, further extending south to Washington State. A second pipeline, the Duke Energy Field Services Pipeline System, is accessible on the north boundary of the property and connects to Tooga Compressor Station, further extending east to Alberta.

2003 Activity

The Company recently announced the terms of a Farmout and Option Agreement with a large independent Canadian oil and gas company on the Orion property. Under the terms of the agreement, the Farmee will have the right to earn a sliding scale interest in three designated blocks of Dynamic's Orion acreage comprising 28,334 gross acres by drilling up to four horizontal test wells into the Upper-Devonion, Jean Marie formation. The first well must spud no later than the end of September 2002.

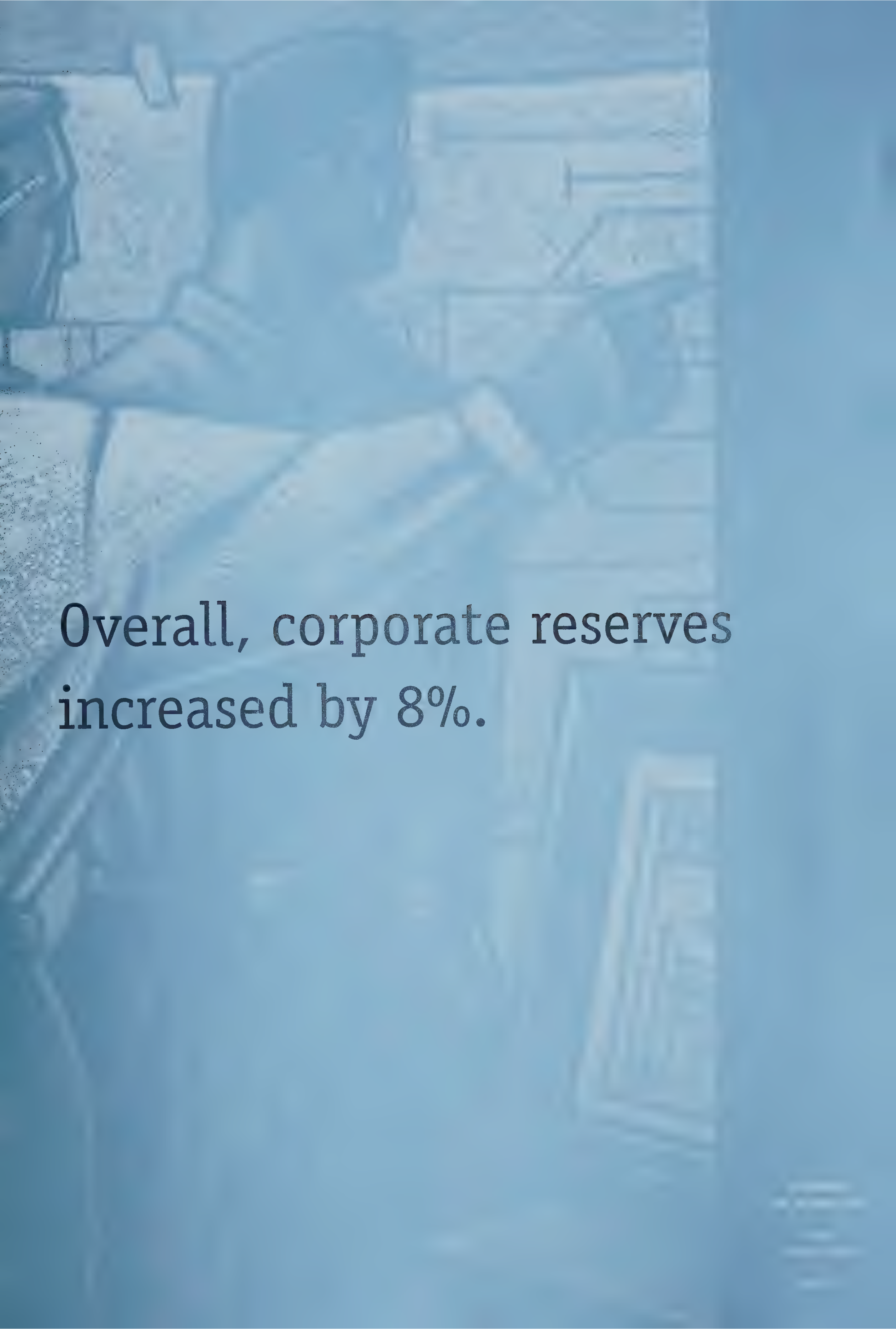


Fraser Valley, British Columbia

The Company was inactive in the Fraser Valley during fiscal 2002. Under a joint venture agreement with Conoco Canada Limited, the partnership continues to own approximately 54,332 gross/18,109 net acres of onshore and offshore petroleum and natural gas rights associated with Permit 802, a validated British Columbia Exploration Permit.

While commercial gas is yet to be discovered in this area, additional drill targets have been identified which are prospective for natural gas accumulation. Permit 802 includes all petroleum and natural gas rights in the immediate offshore area adjacent to Roberts Bank. The Company has identified a large structural feature approximately nineteen square kilometres in area lying just offshore within the boundaries of the Permit. Although structural control is limited, government gravity and proprietary on-shore seismic data support the presence of this feature.

Presently, areas offshore are subject to a restricted access moratorium for petroleum and natural gas activities. More recently, the British Columbia Government has established a task force to study the possibility of removing this moratorium and has begun the public consultation process. Dynamic will continue to monitor any changes in the legislation that may apply to Permit 802 and adjacent areas of potential interest.



Overall, corporate reserves increased by 8%.

... effective April 1, 2002 are prepared by Status ... Alberta ("Status") and are shown in the following tables:

	[illegible]	[illegible] (mbbls)	Equivalent (mboe)
[illegible]	[illegible]	1,908	7,091
[illegible]	[illegible]	229	1,724
[illegible]	[illegible]	321	1,099
[illegible]	[illegible]	2,458	9,915
[illegible]	[illegible]	1,541	9,174
[illegible]	[illegible]	[illegible]	741
[illegible]	[illegible]	[illegible]	[illegible]

... crease were annual production and a downward ... the Peavey/Morinville property. These factors ... h the acquisition of additional working interests

... Albert contains natural gas liquids, while gas from ... is reason that estimated reserves of natural gas liquids ... 424 mbbls or 29%, to 1,901 mbbls over fiscal 2001.

... 770%, to 557 mbbls.

... Halkirk during fiscal 2002 added 623 mboe to ... ch was oil and 38% natural gas and natural

Petroleum and [illegible]

	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Production	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

[illegible] Securities Admin[illegible] commodities and [illegible]

[illegible]

[illegible]

Discounted net present value $(000's) [illegible]

(Before t[illegible])

	[illegible]	[illegible]	[illegible]	[illegible]
Proved [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proved [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total proved and [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total proved and [illegible]	[illegible]	[illegible]	[illegible]	[illegible]

The following discussion and analysis should be read in conjunction with the financial statements and notes to the financial statements in this Annual Report.

Unless otherwise noted, amounts are in thousands of Canadian dollars and production volumes are before royalties.

For comparison purposes, Management's Discussion and Analysis provides, in tabular form, the operating and financial results of Dynamic Oil & Gas, Inc. (the "Company") for the years ended March 31, 2002, 2001 and 2000.

Results of Operations

In fiscal 2002, the Company acquired additional working interest holdings in its producing assets at St. Albert, Alberta (the "St. Albert acquisition"). Through the St. Albert acquisition, the Company's interests increased to 75% from 50% in the majority of gas-related assets and to 75% from 25% in all oil-related assets. Including the effect of the St. Albert acquisition, the Company's product sales mix in fiscal 2002 was 98% weighted toward natural gas and natural gas liquids.

In fiscal 2002, total gross revenues decreased by $8.1 million or 23%, to $26.4 million from fiscal 2001. Due to higher volume sales in fiscal 2002, mainly from the St. Albert acquisition, gross revenues from natural gas increased by $3.7 million over fiscal 2001. This increase was based on the Company's fiscal 2002 weighted average price realized for natural gas. Offsetting this increase was a decrease in gross revenues from natural gas of $10.9 million caused by the weighted average price differential of natural gas ($2.41 per mcf) between fiscals 2002 and 2001.

Also, due to higher volume sales from the St. Albert acquisition in fiscal 2002, gross revenues from natural gas liquids, increased by $1.0 million over fiscal 2001. This increase was based on the Company's fiscal 2002 weighted average price realized for natural gas liquids. Offsetting this increase was a decrease in gross revenues from natural gas liquids of $2.2 million caused by the weighted average price differential of natural gas liquids ($11.35 per bbl) between fiscals 2002 and 2001.

Funds flow from operations during fiscal 2002 decreased by $6.8 million or 38%, to $11.3 million from fiscal 2001. Funds flow in fiscal 2002 and the Company's operating line were, in combination, sufficient to finance the Company's total capital expenditures amounting to $22.1 million, two-thirds of which was used for the St. Albert acquisition. Capital expenditures in fiscal 2001 amounted to $11.6 million.

The Company earnings decreased in fiscal 2002 by $13.2 million or 136% from fiscal 2001, to a net loss of $3.5 million. Based on independent reserves estimated during the latter half of fiscal 2002, the Company evaluated the asset carrying values of its Peavey/Morinville property and made a decision with respect to further development of the property. The evaluation resulted in the Company recording a non-cash write-down of its Peavey/Morinville assets by $6.7 million. This write-down contributed significantly towards the Company's fiscal 2002 net loss of $3.5 million or $0.17 per share.

The Company's overall reserves in fiscal 2002 increased by 741 mboe or 8%, to 9,915 mboe over fiscal 2001. The St. Albert acquisition increased reserves by 2,864 mboe, 72% of which was natural gas. New extensions and discoveries at St. Albert and Halkirk further increased reserves by 623 mboe, 34% of which was natural gas. Offsetting these increases were annual production increases, and decreases due to revisions of previous reserve estimates. Annual production increased by 212 mboe or 22%, to 1,177 mboe. Revisions to previous reserve estimates amounted to a reduction of 1,569 mboe, an amount that was applicable to the Peavey/Morinville property.

Funds flow from operations, earnings and return on equity*

	2002		2001		2000
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Funds flow from operations	**11,337**	**(38)**	18,168	222	5,634
- per share ($)	**0.55**	**(40)**	0.91	213	0.29
Net (loss) earnings	**(3,519)**	**(136)**	9,714	138	4,078
- per share ($)	**(0.17)**	**(135)**	0.49	133	0.21
Shareholder's equity	**16,593**	**(17)**	19,946	99	10,040
Average (loss) return on equity (%)	**(21)**	**(143)**	49	20	41

** When comparing these particular measurements with those of other industry members, see comments relating to facilities leasing costs in "Production Costs" below.*

Production Volumes

In fiscal 2002, daily production volumes increased over fiscal 2001 by an average of 581 boe per day or 22%, to 3,225 boe per day. This was due to increases in natural gas production of 437 boe per day, in natural gas liquids of 101 boe per day, and in oil of 43 boe per day. Of the Company's total annual production of 1,177 mboe in fiscal 2002, 78% was natural gas compared to 79% of fiscal 2001's total 965 mboe.

Of the Company's total production in fiscal 2002, 84% came from the St. Albert field while the remainder originated from six other fields: Peavey/Morinville, Halkirk, Westlock, Legal, Simonette, and Stanmore. The St. Albert acquisition contributed a net increase of 547 boe per day or 94% of the Company's total increase of 581 boe per day.

Daily production rates and total annual production

	2002		2001		2000
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Natural gas (mcf/d)	**15,107**	**21**	12,486	6	11,798
Natural gas liquids (bbls/d)	**631**	**19**	530	(9)	585
Oil (bbls/d)	**76**	**130**	33	(21)	42
Equivalent (boe/d)	**3,225**	**22**	2,644	2	2,593
Total annual production (mboe)	**1,177**	**22**	965	2	947
Gas weighting (%)	**78**		79	4	76

Product Prices

In fiscal 1998, the Company signed a long-term, firm-service sales contract regarding its St. Albert natural gas production. Spot market sales at that time were limited to the Company's production of natural gas liquids. Since then, other available natural gas production has been sold directly by the Company into the spot market.

In fiscal 2002, weighted average prices in the table below show percentage decreases in all commodities compared to fiscal 2001.

Weighted average prices

	2002		2001		2000
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Natural gas ($/mcf)	**3.81**	**(39)**	6.22	129	2.72
Natural gas liquids ($/bbl)	**19.30**	**(37)**	30.64	80	16.98
Oil ($/bbl)	**34.33**	**(21)**	43.60	38	31.53
Equivalent ($/boe)	**22.26**	**(38)**	35.66	113	16.74

Of total gas sold during fiscal 2002, 53% was sold into aggregator portfolios that are comprised of a mix of spot, short-term and long-term contracts. The remaining 47% was sold directly by the Company into the spot market. The table below combines all contract types, aggregator and non-aggregator, to approximate the percentage of the Company's gas being sold into each contract type in each of the past three years.

Aggregators, when used, act as marketing agents for the Company selling the natural gas via a mix of spot, short term (less than one year) and long term contracts. The Company cannot affect the mix of spot, short term and long term contracts that are managed by aggregators, nor is the Company privy to the exact amount of volume sold into each contract type throughout the year. Using general, consistent information provided by aggregators, the table below approximates the Company's mix of contract types for each of the past three years.

			[illegible]	% Change	2000
Spot market – not aggregated	**47%**	**104**	23%	64	14%
Spot market – aggregated	**27%**	**42**	19%	(14)	22%
Total spot market	**74%**	**76**	42%	17	36%
Short-term – aggregated (less than one year)	**1%**	**(89)**	9%	(18)	11%
Long-term – aggregated	**25%**	**(49)**	49%	(8)	53%
Total	**100%**		100%		100%

During fiscal 2002, the Company increased its percentage of total gas sales exposed to spot market pricing by approximately 76% over fiscal 2001. The main reason for this significant increase is the sales of new production generated from the St. Albert acquisition in fiscal 2002.

To date, management has not undertaken any derivative or hedging activities.

Natural Gas, Liquids and Oil Sales

Total gross revenues in fiscal 2002 decreased by $8.1 million or 23%, to $26.4 million from fiscal 2001. Due to higher volume sales in fiscal 2002, total gross revenues increased by $5.1 million over fiscal 2001. This increase was based on the Company's fiscal 2002 weighted average prices realized for all commodities. Offsetting this increase was a decrease in total gross revenues of $13.2 million caused by weighted average price differentials of all products ($13.40 per boe) between fiscals 2002 and 2001.

			[illegible]	Change	2000 Total
Natural gas	**20,944**	**(25)**	28,006	140	11,660
Natural gas liquids	**4,442**	**(25)**	5,935	64	3,620
Oil	**1,016**	**95**	522	7	490
Total	**26,402**	**(23)**	34,463	119	15,770

Royalties

Total royalties including mineral taxes decreased in fiscal 2002 by $3.0 million or 32%, to $6.3 million from fiscal 2001.

The amount that the Company must pay in terms of royalties and mineral taxes is closely related to commodity prices.

In fiscal 2002, Crown royalties decreased by $1.6 million or 55%, to $1.3 million from fiscal 2001. Approximately 15% of the decrease is due to the reversal of a prior-year estimate that was based on available Alberta reference prices in fiscal 2001 during a time of volatile natural gas prices. Another 14% is due to lower production from wells attracting crown royalties and the remainder is due to lower commodity prices used to calculate royalty bases.

In fiscal 2002, freehold and overriding royalties decreased by $2.0 million or 33%, to $4.1 million from fiscal 2001. The St. Albert acquisition was burdened with overriding royalties payable to the previous owner. The elimination of this burden accounted for approximately 7% of the decrease in freehold and overriding royalties. The balance is due to lower commodity prices used to calculate royalty bases.

Freehold mineral taxes increased in fiscal 2002 despite an overall decrease in commodity prices. This non-recurring increase was due to a payment in fiscal 2002 of certain mineral taxes associated with fiscal 2001 production.

Alberta Royalty Tax Credits (ARTC) in fiscal 2002 decreased by $0.3 million or 68%, to $0.2 million from fiscal 2001. This is strictly due to lower Crown royalties on wells eligible for ARTC. Industry advisors indicate that the ARTC is a reasonably secure benefit to Alberta producers through to the end of calendar year 2004.

Royalties and mineral taxes

	2002		2001		2000
	Total	% Change	Total	% Change	Total
Crown	**1,317**	**(55)**	2,958	182	1,050
Freehold and overriding	**4,067**	**(33)**	6,106	113	2,872
Freehold mineral taxes*	**1,116**	**41**	794	48	535
	6,500	**(34)**	9,858	121	4,457
ARTC	**(159)**	**68**	(499)	-	7
Total	**6,341**	**(32)**	9,359	110	4,464

** Based on curent industry trend, the Company reclassified mineral taxes from Production Costs to Royalties in fiscal 2002. For comparison purposes, prior year amounts have been restated in the Statements of Operations and Deficit.*

Production Costs

Of the Company's total production costs, 82% are incurred at St. Albert, therefore, corporate unit production costs of $4.97 per boe are influenced mostly by St. Albert. Unit production costs at St. Albert in fiscal 2002 were $4.84 per boe compared to $4.77 per boe in fiscal 2001.

Production costs

	2002		2001		2000
	Total	% Change	Total	% Change	Total
Production costs* – total	**5,846**	**28**	4,580	24	3,690
Per boe ($)	**4.97**	**5**	4.75	20	3.90

** Based on curent industry trend, the Company reclassified mineral taxes from Production costs to Royalties in fiscal 2002. For comparison purposes, prior year amounts have been restated in the Statements of Operations and Deficit.*

In fiscal 1998, the Company agreed to sell and lease back to Enercap Corporation of Calgary, Alberta ("Enercap") certain gas processing facilities at St. Albert. The initial term of the leaseback is five years, payments having begun late in fiscal 1998. For industry comparison purposes, it is useful to analyze the effect on total production costs of the Enercap sale and leaseback transaction.

In fiscal 2002, facilities leasing costs totaled $0.9 million or $0.84 per boe. Comparatively, facilities leasing costs in fiscal 2001 totaled $1.4 million or $1.38 per boe. After taking into account unit facilities leasing costs, unit production costs in fiscal 2002 are $4.13 per boe ($4.97 less $0.84). Comparatively, in fiscal 2001, unit production costs are $3.37 per boe ($4.75 less $1.38). On this basis, unit costs in fiscal 2002 increased by $0.76 per boe or 23% over fiscal 2001.

One key reason for the increase in fiscal 2002 unit production costs is that increased natural gas production through the St. Albert acquisition is high in liquid content, therefore, more costly to produce. Simultaneously, natural gas production very low in liquid content from the Peavey/Morinville field decreased during fiscal 2002, thereby adding to the overall unit production cost increase. In addition, the cost of utilities during fiscal 2002 was higher than in fiscal 2001.

According to the 2002 Canadian Energy Survey prepared by PricewaterhouseCoopers, the industry unit production cost average for calendar 2001 is $6.63 per boe for conventional oil and gas trusts and $6.11 per boe for the top 100 Canadian Exploration and Production companies ranked by gross revenues.

In fiscal 2003, facilities costs will be $0.5 million. The Company is intending, during fiscal 2003, to exercise its option to purchase the assets under lease for a price of $780,000. (See Notes 4 and 12 to the Financial Statements for further details on the St. Albert gas facility operating lease commitments.)

General and Administrative Expenses

Total general and administrative expenses increased in fiscal 2002 by $0.8 million or 50%, to $2.3 million. During the year, the Company completed the St. Albert acquisition and became Operator of the property. As Operator, the Company took on significant new responsibilities requiring broader staff coverage and outside services. Due mostly to the hiring of four new staff, salaries and benefits increased by $0.5 million in fiscal 2002. Also due to the St. Albert acquisition, interest, insurance and professional fees increased over fiscal 2001.

A category that contributed in fiscal 2002 to a large reduction in general and administrative expense was cost recoveries. Cost recoveries increased 124%, to $0.5 million. Beginning in fiscal 2001 and continuing in fiscal 2002, the Company increased its responsibility as Operator of several new joint venture partnerships. In the role of Operator, the Company is entitled to specified rates of cost recovery pursuant to joint venture agreements.

Interest Expense on Operating Loan

During fiscal 2002, the Company's bank revised the amount made available to the Company under a revolving, demand credit facility. The amount of the facility increased from $10 million to $25 million and then decreased to $21 million. The facility is collateralized by a general assignment of book debts and a floating charge debenture of $35 million.

The interest rate charged by the bank in fiscals 2002, 2001 and 2000 was prime plus 3/8%.

As at March 31, 2002, there was a balance outstanding against the bank facility of $14.8 million. At year-end fiscal 2001, there was no outstanding balance. Pursuant to EIC-122, as issued by the Canadian Institute of Chartered Accountants' Emerging Issues Committee, the year-end balance for fiscal 2002 has been classified as a current liability.

The average level of the operating loan during its usage period of ten months in fiscal 2002 was $12.7 million ($10.5 million annualized), while the effective interest rate was 4.7%. Comparatively, the average level of the operating loan during its nine-month usage period in fiscal 2001 was $3.4 million at an effective interest rate of 6.9%.

In fiscal 2002, interest expense on the operating loan increased by $0.3 million or 106%, to $0.5 million. During the year, the Company utilized its bank credit facility to acquire an additional interest in its St. Albert property. The Company's share of the purchase price paid for this acquisition was $14.7 million.

	[illegible]		2001		2000
	[illegible]	[illegible]	Total	% Change	Total
Interest expense on operating loan*	**495**	**106**	240	24	194
Funds flow times interest coverage	**23**	**(70)**	76	162	29
Average cost per boe ($)	**0.42**	**68**	0.25	19	0.21

** See Notes 1 and 3 to the Financial Statements in this Annual Report for further details on EIC-122 and the Operating loan.*

Liquidity and Capital Resources

As at March 31, 2002, the Company had a working capital deficit of $13.3 million that included a balance owing to its corporate bank of $14.8 million under an operating loan. This resulted in a net debt years-to-repay ratio for fiscal 2002 of 1.2:1.

Under the sale and leaseback transaction concluded in fiscal 1998, the Company agreed to sell and lease back to Enercap certain gas processing facilities at St. Albert. Accordingly, the Company has a future facilities leasing commitment of $0.5 million payable to Enercap extending into fiscal 2003. In November 2002, the Company has the option for $0.8 million to repurchase the gas processing facilities from Enercap and the Company intends to exercise the option.

After adjusting the March 31, 2002 net working capital deficit of $13.3 million by the Enercap leasing commitments and future removal and site restoration costs, the net debt years-to-repay ratio for fiscal 2002 is 1.3:1.

Debt and future items, to funds flow (Years-to-repay ratios)

	2002		[illegible]		[illegible]
	Total	[illegible]	Total	[illegible]	[illegible]
Funds flow from operations	**11,337**	**(38)**	18,168	222	5,634
Working capital	**(13,281)**	**(775)**	1,969	153	(3,716)
Years to repay net debt	**1.2:1**		–		0.7: 1
Future removal and site restoration	**(824)**	**(53)**	(540)	(34)	(402)
Future facilities leasing commitments*	**(468)**	**68**	(1,453)	(48)	(2,788)
Net debt adjusted for future items	**(14,573)**	**–**	(24)	100	(6,906)
Years to repay net debt & future items	**1.3:1**		–		1.2:1

** The Company is intending, during fiscal 2003, to exercise its option to purchase the assets under lease for a price of $780,000. (See Notes 4 and 12 to the Financial Statements for further details on the St. Albert gas facility operating lease commitments.)*

During fiscal 2002, under a normal course issuer bid that terminated on March 31, 2002, the Company repurchased and canceled 178,800 common shares for $0.3 million. During fiscal 2001, under the September 30, 2000 bid authority and under a previous one terminating August 19, 1999, a total of 897,300 common shares were repurchased and canceled for $1.5 million. (See Note 14 to the Financial Statements for details of a bid authorization dated beyond the fiscal year ended March 31, 2002.)

The Company expects that cash generated from operating activities and excess committed borrowing capacity will be sufficient to fund its fiscal 2003 capital expenditure and exploration expense program and to meet financial obligations as they become due.

Amortization, Depletion and Ceiling Test

The Company annually conducts a ceiling test in accordance with accounting guidelines applicable to the operations of all oil and gas companies that follow the successful efforts method of accounting. The test prescribes that the carrying value of petroleum and natural gas properties shall be limited to their estimated future net revenues from proved producing reserves less well reclamation costs.

At each fiscal year-end a portion of oil and gas projects, for which costs have been incurred, have not yet been assigned proved producing reserves. In fiscal 2002, 95% of total costs incurred were attracting amortization and depletion expense ("A&D") while the remainder yet needed to be assigned proved producing reserves. This represented an increase over fiscal 2001 of 20% (95% compared to 75%).

One reason for the 20% increase in A&D during fiscal 2002 is that the Company re-evaluated five potential natural gas wells in which it had participated in years prior to fiscal 2002. Previously, these wells had been completed and suspended pending further evaluation, however, field activities conducted in fiscal 2002 proved these wells unsuccessful. Costs incurred on these five unsuccessful attempts amounting to $2.1 million were expensed and therefore removed from the group of assets that yet needed to be assigned proved producing reserves (see "Exploration Expenses" below.) The other reason for this increase is that projects in progress at the close of fiscal 2001 began producing during fiscal 2002, thereby attracting A&D.

The ratio of A&D to asset costs attracting A&D, should remain fairly consistent from year to year, unless the results of ceiling test adjustments cause significant acceleration of A&D on material properties. In fiscal 2002, the ratio increased to 1:4 from 1:7 in fiscal 2001.

During the last half of fiscal 2002, significant ceiling test adjustments were recorded. Of the $6.8 million in ceiling test adjustments recorded, the Peavey/Morinville property accounted for 99%. Based on independent reserve estimates effective April 1, 2002, the Company re-evaluated its asset carrying values and made a decision with respect to further development of the property. Without factoring in fiscal 2002 ceiling test adjustments, the ratio of A&D to asset costs attracting A&D would have been 1:9, a factor more consistent with those of fiscals 2001 and 2000. As at March 31, 2002, the Company has a total remaining net book value of Peavey/Morinville assets of $1.5 million.

Amortization and Depletion

	2002 Total	2002 % Change	2001 Total	2001 % Change	2000 Total
Amortization and depletion expense ("A&D")	**5,336**	**72**	3,097	100	1,551
Ceiling test adjustments	**6,783**	**–**	36	(61)	93
Total A&D*	**12,119**	**287**	3,133	91	1,644
Assets attracting A&D	**47,525**	**112**	22,435	54	14,566
Total assets	**49,907**	**67**	29,874	54	19,356
Percent of assets attracting A&D to total assets	**95**	**27**	75	–	75
Ratio of A&D to assets attracting A&D	**1:4**		1:7		1:9

** On the Statement of Operations and Deficit, Amortization and Depletion expense of $12,172,943 includes additional debit and credit items. (See Schedule 2: Amortization and Depletion appended to the Notes to the Financial Statements for details.)*

Fiscal 2002 is the fourth full year of the initial five-year term of the St. Albert sale and leaseback agreement. Amortization of the deferred gain realized on the sale of $0.2 million was recorded (fiscal 2001 - $0.3 million). (See "Production Costs" above for further discussion on the agreement.)

Exploration Expenses

Exploration expenses in fiscal 2002 increased by $2.7 million or 142%, to $4.6 million over fiscal 2001. The most significant increase in exploration costs was due to the expensing of drilling costs associated with unsuccessful wells that were drilled during fiscal 2002 and prior.

Four wells drilled during fiscal 2002 were unsuccessful, two at Peavey/Morinville and one each at Quirk Creek and Alexander. The Company also conducted a re-entry/workover operation on one St. Albert well that was unsuccessful. Costs incurred on these five unsuccessful attempts amounting to $1.7 million were expensed in the year.

Five wells drilled prior to fiscal 2002 were also unsuccessful, four at Peavey/Morinville and one at Orion. Previously, these wells had been completed and suspended pending further evaluation. However, field activities conducted in fiscal 2002 proved these wells unsuccessful. Costs incurred on these five unsuccessful attempts amounting to $2.1 million were expensed in the year.

Exploration expenses associated with seismic programs conducted during fiscal 2002 amounted to $0.6 million. One third of this amount was incurred at St. Albert and Peavey/Morinville, the remainder at other central Alberta properties. A total of $1.1 million has been approved for spending on seismic programs in the Company's exploration budget for fiscal 2003.

Gain on Sale of Natural Gas and Oil Interests

In fiscal 2002, there were no significant transactions to report.

In fiscal 2001, the Company sold a 50% interest in a portion of its Orion leases in northeast British Columbia in exchange for a farm-in agreement with another company. The proceeds on the sale were $1.0 million and the associated gain amounted to $0.6 million.

Income Taxes

The Company uses the liability method of tax allocation in accounting for income taxes. Future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantially enacted rates and laws that will be in effect when the differences are expected to reverse.

The effective income tax rate of fiscal 2002 was a recovery of 35.1%, compared with an expense of 32.8% in fiscal 2001. As at March 31 for each of the last three years, the Company had the following income tax pools available to shelter future income from taxes.

Income tax pools available

	2002	2001	2000	Maximum annual deduction
Canadian exploration expense	–	–	5,219	100%
Non-capital losses	–	–	318	100%
Share issue costs	–	–	95	100%
Canadian development expense	**3,772**	3,307	1,732	30%
Undepreciated capital costs	**10,297**	5,554	3,274	20%–100%
Canadian oil and gas property expense	**16,471**	3,986	4,460	10%
Total	**30,540**	12,847	15,098	

Capital Expenditures

Capital expenditures increased in fiscal 2002 by $10.5 million or 91%, to $22.1 million over fiscal 2001. Field expenditures amounted to $22.0 million and office expenditures amounted to $0.1 million.

Of the $22.0 million spent on field expenditures in fiscal 2002, 80% was spent at St. Albert, 14% at Halkirk, 3% at Peavey/Morinville and 3% at Alexander and two other central Alberta properties. Included in the amount spent at St. Albert was $14.7 million for the purchase price of the St. Albert acquisition.

Of the $7.7 million spent on drilling, completions and tie-ins, 5% was on exploratory drilling, 8% on development drilling, 41% on completions and 46% on equipping.

Capital expenditures

	2002	% Change	2001	% Change	2000
Drilling, completions and tie-ins	**7,678**	**11**	6,939	150	2,777
Facilities	**1,757**	**(50)**	3,522	245	1,022
Land acquisitions	**12,560**	**1,105**	1,042	(43)	1,828
Field expenditures	**21,995**	**91**	11,503	104	5,627
Furniture, fixtures and computer	**116**	**47**	79	(21)	100
Total	**22,111**	**91**	11,582	102	5,727

The Company has established a capital budget for fiscal 2003 of $17.0 million which is expected to be funded from operations. Of that amount, it is expected that 52% will be spent on exploration projects and 48% on development projects.

Business Risks

The oil and gas industry is exposed to a variety of risks including the uncertainty of finding and recovering new economic reserves, the performance of hydrocarbon reservoirs, securing markets for production, commodity prices, interest rate fluctuations, potential damage to or malfunction of equipment and changes to income tax, royalty, environmental or other governmental regulations.

The Company mitigates these risks to the extent it is able by:

- employing highly-skilled staff and focusing them in areas where they have a strong knowledge base in order to maximize value.
- utilizing competent, professional consultants as support teams to company staff.
- performing careful and thorough geophysical, geological and engineering analyses of each prospect.
- using current, cost-effective and where feasible, leading-edge technology.
- maintaining adequate levels of property, liability and business interruption insurance.
- focusing on a limited number of core properties.
- striving to be a low-cost producer to maximize netbacks.
- maintaining a balanced portfolio of sales contracts.

Corporate Governance

In 1999, the Toronto Stock Exchange Committee on Corporate Governance in Canada issued a series of proposed guidelines for effective corporate governance, and the Toronto Stock Exchange now requires listed companies to disclose their corporate governance, which the Company has done in its Annual General Meeting Information Circular. The Board of Directors of the Company has established corporate governance practices, and reviews them regularly to ensure they are appropriate in relation to the guidelines.

Outlook

During fiscal 2003, the Company expects to conduct an active development program in central Alberta. Drilling plans include a nine-well program for new natural gas and oil reserves at St. Albert and a four-well program for new natural gas reserves at Halkirk. Completions and various production-enhancing projects on both properties are planned.

The Company also expects to increase exploration activities during fiscal 2003. Plans include the drilling of up to four wells and one re-entry in central Alberta. They also include the drilling of up to three wells in northeastern British Columbia.

The Company favours natural gas and intends to grow its gas reserves in Western Canada. The Company owns at St. Albert, however, a 75% working interest in mineral rights having several oil targets, and infrastructure with ample capacity. Drilling for these targets is expected in fiscal 2003.

St. Albert is a prime, core property for the Company. It produces natural gas, natural gas liquids and oil, and remains prospective for all three. A key strategic objective of the Company's business plan is to establish other core properties and the plan for fiscal 2003 includes projects aimed at that objective.

Sensitivity Analysis

In fiscal 2002, the Company's total gross revenue was comprised of 80% natural gas and 17% natural gas liquids. Accordingly, the Company's funds flow is very sensitive to fluctuations in the price of these two commodities. Based on sales volumes, weighted average prices of natural gas and natural gas liquids, and the average annual operating loan balance outstanding during fiscal 2002, the following table shows the effect on funds flow of certain changes in volume, price and interest rates.

Sensitivity Analysis

	Change in			[illegible]	
	Volume	*Price*	*Rate*	[illegible]	[illegible]
Natural gas production (mmcf/d)	1	–	–	1,389	0.070
Natural gas price ($/mcf)	–	0.10	–	547	0.027
Natural gas liquids (bbls/d)	100	–	–	704	0.034
Natural gas liquids ($/bbl)	–	1.00	–	230	0.011
Interest rate (%)	–	–	1	33	0.002

Special Note Regarding Forward-Looking Statements

Certain statements in this report, including those appearing under the caption "Management's Discussion and Analysis", constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such statements are generally identifiable by the terminology used such as "plan", "expect", "estimate", "budget", or other similar words.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for natural gas, natural gas liquids and oil products; the ability to produce and transport natural gas, natural gas liquids and oil; the results of exploration and development drilling and related activities; economic conditions in the country and provinces in which the Company carries on business; actions by governmental authorities including increases in taxes, changes in environmental and other regulations, and renegotiations of contracts; political uncertainty, including actions by insurgent groups or other conflict and the negotiation and closing of material contracts. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available. In that regard, any statements as to future natural gas, natural gas liquids or oil production levels, capital expenditures, the allocation of capital expenditures to exploration and development activities, sources of funding for its capital program, drilling of new wells, demand for natural gas, natural gas liquids and oil products, expenditures and allowances relating to environmental matters, dates by which certain areas will be developed or will come on-stream, dates by which transactions are expected to close, cash flows, debt levels and changes in any of the foregoing are forward-looking statements, and there can be no assurance that the expectations conveyed by such forward-looking statements will, in fact, be realized.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking were made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by the cautionary statements.

Financial Statements

REPORT OF MANAGEMENT

The accompanying financial statements and all information in the Annual Report are the responsibility of management. The financial statements have been prepared in accordance with accounting policies detailed in the notes to the financial statements and in accordance with generally accepted Canadian accounting principles, and where necessary includes amounts based on management's informed judgements and estimates.

Financial information throughout the Annual Report is consistent with the financial statements.

Management maintains an appropriate system of accounting and administrative controls to provide reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records are properly maintained to provide reliable financial statements.

Ernst & Young LLP, the Company's external auditors, have audited the financial statements in accordance with generally accepted auditing standards in Canada. Their examination included a review of accounting systems and detailed audit procedures were performed on all material transactions. Their report appears below.

The Board of Directors, through its Audit Committee, is responsible for assuring that management fulfills its financial reporting responsibilities. This Committee reviews the financial statements and gives its recommendation for approval to the Board of Directors.

Wayne J. Babcock

Wayne J. Babcock
President & Chief Executive Officer

M. Bardell

Michael A. Bardell
Chief Financial Officer & Corporate Secretary

AUDITORS' REPORT

To the Shareholders of Dynamic Oil & Gas, Inc.

We have audited the balance sheets of Dynamic Oil & Gas, Inc. as at March 31, 2002 and 2001 and the statements of operations and deficit and cash flows for each of the years in the three year period ended March 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada and the United States. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended March 31, 2002 in accordance with Canadian generally accepted accounting principles. As required by the Company Act of British Columbia, we report that, in our opinion, these principles have been applied on a consistent basis.

Ernst & Young LLP

Vancouver, Canada,
June 14, 2002.

Chartered Accountants

BALANCE SHEETS

(in Canadian dollars)

As at March 31

	2002 $	2001 $
[illegible]		
Current		
Cash and cash equivalents	**–**	3,493,448
Accounts receivable *[note 9]*	**5,979,532**	4,444,834
Prepaid expenses	**365,227**	240,466
Total current assets	**6,344,759**	8,178,748
Future income tax asset *[note 6]*	**279,000**	–
Natural gas and oil interests *[note 2]*	**30,365,636**	21,678,527
Capital assets *[note 2]*	**162,499**	133,380
	37,151,894	29,990,655
[illegible] SHAREHOLDERS' EQUITY		
Current		
Bank indebtedness	**842,812**	–
Operating loan *[note 3]*	**14,750,000**	–
Accounts payable and accrued liabilities	**3,611,314**	5,664,739
Income taxes payable *[note 6]*	**421,360**	545,144
Total current liabilities	**19,625,486**	6,209,883
Deferred gain on sale *[note 4]*	**109,327**	339,601
Provision for future removal and site restoration	**824,098**	539,730
Future income tax liability *[note 6]*	**–**	2,955,000
Total liabilities	**20,558,911**	10,044,214
Share capital *[note 5]*	**20,914,522**	20,641,720
Deficit	**(4,321,539)**	(695,279)
Total shareholders' equity	**16,592,983**	19,946,441
	37,151,894	29,990,655

Commitments *[note 12]*

See accompanying notes and schedules.

On behalf of the Board:

Director *Director*

STATEMENTS OF OPERATIONS AND DEFICIT

(in Canadian dollars)

Years ended March 31

	2002 $	2001 $	2000 $
REVENUE			
Natural gas, liquids and oil sales	**26,401,872**	34,462,676	15,770,327
Royalties *[note 10]*	**(6,500,447)**	(9,857,954)	(4,634,996)
Production costs	**(5,845,958)**	(4,579,845)	(3,690,464)
	14,055,467	20,024,877	7,444,867
Alberta royalty tax credit	**159,274**	498,773	(7,134)
	14,214,741	20,523,650	7,437,733
EXPENSES			
General and administrative *[schedule 1]*	**2,347,212**	1,569,175	1,618,821
Interest expense on operating loan	**494,685**	240,420	194,487
Interest income	**(22,066)**	(25,601)	(9,583)
	2,819,831	1,783,994	1,803,725
Earnings from operations before the following:	**11,394,910**	18,739,656	5,634,008
Amortization and depletion *[schedule 2]*	**12,172,943**	3,006,964	1,464,155
Exploration expenses *[schedule 3]*	**4,646,018**	1,923,194	1,299,276
Gain on sale of natural gas and oil interests	**(4,566)**	(639,532)	–
(Loss) earnings before taxes	**(5,419,485)**	14,449,030	2,870,577
Current income tax expense *[note 6]*	**57,600**	572,000	–
Future income tax (recovery) expense *[note 6]*	**(1,958,000)**	4,163,000	(1,208,000)
Net (loss) earnings	**(3,519,085)**	9,714,030	4,078,577
Deficit, beginning of year	**(695,279)**	(10,379,392)	(13,943,643)
Premium on purchase and cancellation of common shares *[note 5[e]]*	**(107,175)**	(29,917)	(510,094)
Share issue costs	**–**	–	(4,232)
Deficit, end of year	**(4,321,539)**	(695,279)	(10,379,392)
Earnings per share *[note 7]*			
basic	**(0.17)**	0.49	0.21
diluted	**(0.17)**	0.48	0.20

See accompanying notes and schedules.

STATEMENTS OF CASH FLOWS

(in Canadian dollars)

Years ended March 31

	2002 $	2001 $	2000 $
OPERATING ACTIVITIES			
(Loss) earnings	**(3,519,085)**	9,714,030	4,078,577
Add (deduct) items not involving cash:			
Amortization and depletion	**12,172,943**	3,006,964	1,464,155
Future income taxes	**(1,958,000)**	4,163,000	(1,208,000)
Exploration expenses	**4,646,018**	1,923,194	1,299,276
Gain on sale of natural gas and oil interests	**(4,566)**	(639,532)	–
Funds flow from operations	**11,337,310**	18,167,656	5,634,008
Changes in non-cash working capital affecting operating activities *[note 8[a]]*	**(1,558,807)**	1,096,162	(963,834)
Cash provided by operating activities	**9,778,503**	19,263,818	4,670,174
FINANCING ACTIVITIES			
Bank indebtedness	**842,812**	–	–
Operating loan	**14,750,000**	(6,000,000)	3,750,000
Shares issued for cash	**455,420**	200,000	121,000
Share repurchases	**(289,793)**	(89,689)	(1,376,723)
Share issue costs	**–**	–	(4,232)
Cash provided by (used in) financing activities	**15,758,439**	(5,889,689)	2,490,045
INVESTING ACTIVITIES			
Purchase of capital assets	**(116,180)**	(78,749)	(100,113)
Natural gas and oil interests	**(21,994,897)**	(11,502,902)	(5,626,771)
Exploration expenses	**(4,646,018)**	(1,923,194)	(1,299,276)
Proceeds on sale of natural gas and oil interests	**4,566**	1,072,395	–
Changes in non-cash working capital affecting investing activities *[note 8[b]]*	**(2,277,861)**	1,109,888	824,512
Cash used in financing activities	**(29,030,390)**	(11,322,562)	(6,201,648)
(Decrease) increase in cash and cash equivalents	**(3,493,448)**	2,051,567	958,571
Cash and cash equivalents, beginning of year	**3,493,448**	1,441,881	483,310
Cash and cash equivalents, end of year	**–**	3,493,448	1,441,881
Supplemental disclosures of cash flow information			
Cash paid during the year for:			
Interest	**589,549**	259,230	213,109
Income taxes	**1,167,720**	26,856	—
Funds flow from operations per share *[note 7]*			
– basic	**0.55**	0.91	0.29
– diluted	**0.55**	0.89	0.28

See accompanying notes and schedules.

(in Canadian dollars)

March 31, 2002, 2001 and 2000

1. Summary of Significant Accounting Policies

Dynamic Oil & Gas, Inc. (the "Company") is engaged in the acquisition, exploration, development and production of natural gas and oil interests. The Company's operations are conducted in Western Canada.

Accounting principles

The Company prepares its accounts in accordance with Canadian generally accepted accounting principles which, as applied in these financial statements, conform in all material respects with United States generally accepted accounting principles, except as explained in note 11.

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

Natural gas and oil interests

The Company uses the successful efforts method to account for its natural gas and oil interests. Lease acquisition costs are amortized over their holding period prior to the discovery of proved reserves. Geological and geophysical costs are expensed in the period in which they are incurred and costs of drilling an unsuccessful well are expensed when it becomes known the well did not result in a discovery of proved reserves. All other costs of exploring and developing for proved reserves become capitalized natural gas and oil interests.

The cost of proved producing interests including related plant and equipment are depleted on a unit-of-production basis, based on proved producing natural gas and oil reserves.

Natural gas and oil interests are recorded at cost less accumulated provisions for depreciation, depletion and amortization. Natural gas and oil interests are assessed periodically for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows.

Cash and cash equivalents

Cash and cash equivalents are recorded at cost, which approximates current market value.

Cash and cash equivalents is comprised of cash balances held at financial institutions and in bankers acceptances with an average interest rate of 4.5% and original maturities of three months or less.

Joint interests

Substantially all of the acquisition, exploration, development and production activities of the Company are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Future removal and site restoration

Costs for the future removal and site restoration of natural gas and oil interests are based on estimates of liabilities and year of abandonment. The estimates of the liabilities are based on engineering estimates which consider past experience, current regulations, technology and industry standards. Costs are amortized to earnings on a straight-line basis to the year of abandonment.

1. Summary of Significant Accounting Policies, *continued*

[illegible]

Capital assets are recorded at cost, less accumulated amortization. Amortization is provided on a straight-line basis at the following rates:

Furniture, fixtures and equipment	– 0% per annum
Computer equipment	– 33.3% per annum

[illegible]

The liability method of tax allocation is used in accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

[illegible]

The Company has one stock-based compensation plan. No compensation expense is recognized for this plan when stock options are issued to directors, officers, employees or consultants. Any consideration paid by option holders on exercise of stock options is credited to share capital.

[illegible]

Cash and other monetary assets and liabilities representing amounts in foreign currencies owing to or by the Company are translated at year-end rates. Non-monetary assets and liabilities are translated at historical rates. Revenues and expenses are translated at the actual rate of exchange in effect at the time of the transaction. Translation gains and losses are included in income in the period incurred.

[illegible]

The amounts recorded for depletion and amortization of natural gas and oil interests and the provision for future removal and site restoration are based on estimates. Assessments for impairments in asset carrying costs are based on estimates of proved producing reserves, production rates, natural gas and oil prices, future costs and other relevant assumptions. By their nature these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

[illegible]

Revenues from crude oil, natural gas and natural gas liquids are recorded when title passes to customers.

[illegible]

The deferred gain is amortized to income over the lease back term.

[illegible]

Effective January 1, 2001, the Company adopted, on a retroactive basis, the new recommendations of the CICA with respect to the presentation and computation of earnings per share. The new recommendations require the presentation of basic and diluted earnings per share figures for net income on the Statements of Operations. The treasury stock method is to be used for determining the dilutive effect of warrants and options. Prior to the adoption of the new recommendations, the imputed earnings method was used. The 2001 and 2000 comparative Financial Statements and Notes to the Financial Statements have been restated to conform to the 2001 presentation. Application of the new recommendations in 2001 had no impact on the basic and diluted earnings per share figures and in 2000 diluted earnings per share were increased by $0.01.

[illegible]

In October 2001, the Canadian Institute of Chartered Accountants' Emerging Issues Committee (EIC) issued EIC-122, "Balance Sheet Classification of Callable Debt Obligations and Debt Obligations Expected to be Refinanced." As a result of applying these new recommendations, the Company's obligations that by their terms are due on demand, even though liquidation may not be expected within one year, are re-classified from long-term to current liabilities. As a result, at March 31, 2002 the outstanding balance of the Company's operating loan of $14,750,000 [2001 – $nil] has been classified as a current liability [note 3].

2. Natural Gas and Oil Interests, and Capital Assets

	Cost $	Accumulated amortization and depletion $	Net book value $
2002			
Natural gas and oil interests	**49,453,746**	**19,088,110**	**30,365,636**
Furniture, fixtures and computer equipment	**453,733**	**291,234**	**162,499**
2001			
Natural gas and oil interests	29,536,063	7,857,536	21,678,527
Furniture, fixtures and computer equipment	337,554	204,174	133,380

In 2002, the Company recorded asset write-downs of $6,783,248 [2001 – $35,712; 2000 – $93,058] to reflect the excess of the net book value of the Company's natural gas and oil interests over its estimated recoverable amounts. The Company's assets at Peavey/Morinville were written down by $6,697,431 and at Simonette by $85,817. The write-downs were included in amortization and depletion expense.

Acquisition of additional St. Albert oil and gas interest

Effective April 1, 2001, the Company acquired additional interests in its St. Albert, Alberta property from Fletcher Challenge Oil & Gas Inc. The closing date of the purchase and sale agreement was June 29, 2001. Dynamic's interest in the property's assets, pursuant to the acquisition, increased as follows:

Description of assets	*[illegible] interest*	*[illegible]*
Producing gas wells – 19	50%	75%
Producing oil wells – 7	25%	75%
Oil battery – 1	25%	75%
Solution gas plant – 1	–	25%
Sales gas pipeline complete with facilities – 1	–	25%

Pursuant to the sale and leaseback agreement dated December 18, 1997 [see note 12[a]], the Company has the option to repurchase a 50% interest in the solution gas plant and sales gas pipeline complete with certain gathering and processing facilities. The Company currently leases the 50% option interest, however, 75% of the net income from the operation of the facilities belongs to Dynamic. Under the June 29, 2001 purchase and sale agreement, 25% of all of the assets described above have been acquired on an equal share basis by two other partner companies. Dynamic has become the Operator of the property.

Dynamic's share of the purchase price paid for these new assets was $14,739,471.

3. Operating Loan

The Company's bank, the National Bank of Canada, revised the amount made available to the Company under a revolving, demand credit facility during 2002. The amount of the facility increased from $10,000,000 to $25,000,000 and then decreased to $21,000,000. Principal balances outstanding bear interest at prime plus 3/8% and are collateralized by a general assignment of book debts and a floating charge debenture of $35,000,000 covering all assets of the Company. The effective average interest paid during 2002 was 4.7% [2001 – 6.9%]. A standby fee of 0.125% per annum is levied on the unused portion of the facility.

4. St. Albert Sale and Leaseback

On December 18, 1997, the Company agreed to sell and lease back, for an initial term of five years, its St. Albert gas processing facilities to Enercap Corporation of Calgary, Alberta ("Enercap"). The impact on the Company of the sale was a reduction of natural gas and oil interests of $3,427,846, the elimination of a debenture payable in 1998 to Enercap of $4,832,352 and a gain on sale of $1,404,506. The gain is being deferred and amortized to income over the leaseback term [see note 12[a]].

5. Share Capital

Authorized 60,000,000 common shares without par value.

[a] The Company had the following shares issued and outstanding:

	[illegible]		2001		[illegible]	
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Outstanding, beginning of year	**20,145,930**	**20,641,720**	19,848,256	20,419,742	20,388,732	21,079,371
Shares issued for cash:						
Stock options exercised	**495,100**	**455,420**	279,000	200,000	222,500	121,000
Issued on conversion of collateralized convertible debt *[note 5[d]]*	**–**	**–**	76,774	81,750	76,224	86,000
Share repurchases and cancellations	**(178,800)**	**(182,618)**	(58,100)	(59,772)	(839,200)	(866,629)
Outstanding, end of year	**20,462,230**	**20,914,522**	20,145,930	20,641,720	19,848,256	20,419,742

[b] Under the Company's stock option plan, the Company has granted options to inside directors, officers, employees and consultants with a maximum term of five years. Those granted prior to February 28, 2001 vest upon date of grant; those granted after February 28, 2001 vest in equal amounts over three years from the date of grant.

Also under the plan, options granted to the Company's outside directors have a maximum term of ten years and vest upon date of grant.

The exercise price of each option granted under the plan equals the amount designated in the individual agreement, which is based on the fair value of the stock at the date of grant.

A summary of the status of the Company stock option plan as of March 31, 2002, 2001 and 2000 is presented below:

	[illegible]		[illegible]		2000	
	Number of shares	*Weighted average option price*	*Number of shares*	*Weighted average option price*	*Number of shares*	*Weighted average option price*
Outstanding at beginning of year	**1,855,350**	**1.29**	1,599,100	1.29	1,776,600	1.19
Granted	**570,000**	**1.87**	535,250	2.00	45,000	1.45
Exercised	**(495,100)**	**0.92**	(279,000)	0.72	(222,500)	0.54
Outstanding at end of year	**1,930,250**	**1.83**	1,855,350	1.29	1,599,100	1.29
Options exercisable at year end	**1,458,750**	**1.84**	1,855,350	1.29	1,599,100	1.29

[c] The Company has options outstanding and exercisable as follows:

Number	Exercise price $	Expiry date
740,000	1.72	April 22, 2003
40,000	1.72	July 14, 2003
45,000	1.45	January 24, 2005
30,000	1.75	August 1, 2005
353,000	2.10	September 29, 2005
112,500	1.72	August 17, 2010
18,750	2.10	September 29, 2010
7,000	2.17	March 1, 2006
52,500	2.15	April 30, 2011
60,000	2.10	August 23, 2011
1,458,750	1.84	

These options have a weighted average remaining contractual life of 3.06 years.

[d] The Company issued on November 15, 1995 convertible debentures of $1,000,000 that were collateralized by a general security agreement charging all Company assets. Interest was to be paid monthly at an annual rate of 10% with the principal to be repaid at any time after November 15, 1996 but no later than November 15, 2000. At the option of the debenture holders, all principal amounts were converted into common shares of the Company in the fiscal years and at weighted average prices in the table below.

Years of conversion	Shares issued upon conversion [illegible]	Weighted average price [illegible]	Original principa [illegible]
2001	76,774	1.06	81,750
2000	76,224	1.13	86,000
1997-1999	1,152,557	0.72	832,250
Total	1,305,555	0.77	1,000,000

[e] Pursuant to the following normal course issuer bids, the Company was authorized to repurchase and cancel common shares on the open market through the facilities of the Toronto Stock Exchange and NASDAQ:

Normal course issuer bid date of Commencement	Termination	Share repurchases/ cancellations au[illegible]
9-Apr-01	31-Mar-02	1,000,000
1-Oct-99	30-Sep-00	1,000,000
17-Aug-98	16-Aug-99	980,680

Under these normal course issuer bids, the Company purchased and recorded the following:

	2002		2001		[illegible]	
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Bid termination date: 31-Mar-02	**(178,800)**	**(289,793)**	–	–	–	–
Bid termination date: 30-Sep-00	–	–	(58,100)	(89,689)	(372,900)	(571,607)
Bid termination date: 16-Aug-99	–	–	–	–	(466,300)	(805,116)
	(178,800)	**(289,793)**	(58,100)	(89,689)	(839,200)	(1,376,723)
Average purchase price	**$1.62**		$1.54		$1.64	
Recorded as an increase of deficit		**107,175**		29,917		510,094
Recorded as a reduction of share capital		**(182,618)**		(59,772)		(866,629)

6. Income Taxes

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's future tax liabilities as of March 31, 2002 are as follows:

	2002 $	2001 $
Long term future tax assets (liabilities):		
CCA in excess of book depreciation	**(46,000)**	(3,289,000)
Finance charges	**2,000**	8,000
Deferred gain recognized for tax purposes	**46,000**	126,000
Provision for future removal and site restoration costs	**277,000**	200,000
Net future tax assets (liabilities)	**279,000**	(2,955,000)

Significant components of the provision for income taxes attributable to continuing operations are as follows:

	Liability method		
	2002 $	*2001* $	2000 $
Current tax expense	**57,600**	572,000	–
Future income tax benefit resulting from recognition of loss carryforwards	**–**	–	(144,000)
Future income tax benefit resulting from recognition of attributed royalty income carryforwards	**–**	–	(98,000)
Future income tax expense (benefit) relating to origination and reversal of temporary differences	**(2,666,800)**	4,740,000	(966,000)
Effect of reduction in substantively enacted rates	**708,800**	(577,000)	–
Income tax (recovery) expense	**(1,900,400)**	4,735,000	(1,208,000)

The reconciliation of income tax attributable to continuing operations computed at the statutory tax rates to income tax (recovery) expense is:

	Liability method					
	[illegible]		[illegible]		[illegible]	
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Tax at combined federal and provincial rates	**(2,371,000)**	**43.75**	6,483,000	44.87	1,295,000	45.12
Tax effect of non-deductible crown royalties	**1,068,000**		1,329,000		701,000	
Tax effect of income not taxable	**(64,900)**		(224,000)		3,000	
Amortization of deferred gain previously recognized for tax purposes	**–**		–		(156,000)	
Tax effect of origination and reversal of temporary differences	**–**		–		389,000	
Tax effect of resource allowance	**(1,290,300)**		(2,295,000)		(736,000)	
Utilization of non-capital losses not previously recognized for accounting purposes	**–**		–		(1,496,000)	
Recognition of loss carryforwards still available	**–**		–		(144,000)	
Recognition of attributed royalty income carryforwards still available	**–**		–		(98,000)	
Large Corporation Tax in excess of surtax	**49,000**		19,000		–	
Recognition of benefit of temporary differences	**–**		–		(966,000)	
Effect of changes in tax rates	**708,800**		(577,000)		–	
	(1,900,400)		4,735,000		(1,208,000)	

7. Earnings per Share and Funds Flow From Operations

Basic net (loss) earnings per share was calculated on the basis of the weighted average number of shares outstanding for the year of 20,365,031 [2001 – 19,937,585; 2000 – 19,709,904]. The weighted average number of shares outstanding for the diluted calculation in 2002 was 20,466,543 [2001 – 20,444,979; 2000 – 20,174,485].

	[illegible]	[illegible]	[illegible]
Numerator			
Net (loss) earnings for the year	**(3,519,085)**	9,714,030	4,078,577
Denominator			
Weighted average number of common shares outstanding	**20,365,031**	19,937,585	19,709,904
Effect of dilutive stock options	**101,512**	507,934	464,581
	20,466,543	20,444,979	20,174,485
Basic (loss) earnings per share	**(0.17)**	0.49	0.21
Diluted (loss) earnings per share	**(0.17)**	0.48	0.20

Funds flow from operations per share (basic and diluted) is calculated by dividing the funds flow from operations by the weighted average number of common shares outstanding as indicated above.

8. Changes in Non-Cash Working Capital Balances

[a] Changes affecting operating activities comprise:

	2002 $	2001 $	2000 $
Accounts receivable	**(581,264)**	(2,463,146)	(352,708)
Prepaid expenses	**(124,761)**	(122,782)	(23,928)
Accounts payable and accrued liabilities	**(728,998)**	3,136,946	(587,198)
Income taxes payable	**(123,784)**	545,144	–
	(1,558,807)	1,096,162	(963,834)

[b] Changes affecting investing activities comprise:

	2002 $	2001 $	2000 $
Accounts receivable	**(953,434)**	217,404	302,402
Accounts payable	**(1,324,427)**	892,484	522,110
	(2,277,861)	1,109,888	824,512

9. Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bank indebtedness, operating loan and accounts payable. The carrying values of these financial instruments approximate their fair value.

Substantially all of the Company's accounts receivable at March 31, 2002 and 2001 result from the sale of natural gas, natural gas liquids and oil to other companies in the oil and gas industry. This concentration of customers may impact the Company's overall credit risk, either positively or negatively, in that such entities may be similarly affected by industry-wide changes in economic or other conditions. Historically to date, the Company has incurred no credit losses against its receivables.

10. Overriding Royalty

Three officers of the Company receive compensation pursuant to royalty agreements that have previously been approved by shareholders. The Company pays an overriding royalty interest of 1% of the Company's share of gross monthly production of all petroleum substances produced or deemed to be produced and marketed from or allocated to each well on all lands acquired by the Company since June 1, 1986 for two of the three officers and June 1, 1987 for the third officer. In 2002, the overriding royalty expense included in royalties is $745,994 [2001 – $934,338; 2000 – $366,746].

11. Reconciliation of Generally Accepted Accounting Principles

The Company prepares its accounts in accordance with Canadian generally accepted accounting principles (Canadian GAAP) which for the most part, parallel United States generally accepted accounting principles (U.S. GAAP). The following tables reflect the major differences in accounting principles.

Consolidated net (loss) earnings under U.S. GAAP would be:

For the years ended March 31	2002 $	2001 $	2000 $
Net (loss) earnings under Canadian GAAP	**(3,519,085)**	9,714,030	4,078,577
Adjustments			
Options issued for services [a]	–	(20,100)	–
Ceiling test adjustment to natural gas properties [b]	**(216,100)**	–	(145,050)
Income taxes [c]	**669,100**	(577,000)	–
Net (loss) earnings and comprehensive (loss) earnings under U.S. GAAP	**(3,066,085)**	9,116,930	3,933,527
Common shares – weighted average	**20,365,031**	19,937,585	19,709,904
Net (loss) earnings per common share under U.S. GAAP			
– basic	**(0.15)**	0.46	0.20
– diluted	**(0.15)**	0.45	0.19

After adjusting for certain differences, selected consolidated balance sheet items under U.S. GAAP would be:

	2002		*2001*	
	Canadian basis $	*U.S. basis* $	*Canadian basis* $	*U.S. basis* $
Future income tax asset [c]	**279,000**	**371,100**	–	–
Future income tax liability [c]	–	–	2,955,000	3,532,000
Natural gas and oil interests [b]	**30,365,636**	**30,149,536**	21,678,527	21,678,527
Share capital [a, d]	**20,914,522**	**21,882,682**	20,641,720	21,609,880
Deficit [a, b, c, d]	**(4,321,539)**	**(5,421,657)**	(695,279)	(2,355,572)

[a] Stock-based compensation

Under Canadian GAAP, no compensation expense is recognized when stock options are issued to directors, employees or consultants. Under U.S. GAAP, the Company accounts for stock-based compensation arrangements using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") for employees and directors and the fair value method under Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123") for consultants. Under APB 25, compensation expense for employees and directors is based on the difference between the fair value of the Company's stock and the exercise price if any, on the date of the grant. Under SFAS 123, the Company accounts for stock options issued to consultants at fair value. The Company uses the Black-Scholes option pricing model to determine the fair value of stock options granted to consultants. While the Company follows APB 25 for employees and directors, it does comply with the disclosure provisions of SFAS 123.

Under U.S. GAAP, certain stock options issued by the Company would be considered compensatory in nature and such stock options are charged to compensation expense and credited to share capital.

During 2002, the Company's option grants included 20,000 stock options issued to a consultant for services at $1.75 per option, resulting in administrative expense recorded in the U.S. GAAP financial statements of $nil in accordance with SFAS 123. These options vest over three years in increments of 6,667 per year beginning February 28, 2003 and expiring on February 28, 2007. At the time of the grant, the fair value of the options was $14,800,an amount that will be recognized as compensation expense evenly over the next three years as the options vest.

11. Reconciliation of Generally Accepted Accounting Principles, *continued*

During 2002, the Company's option grants consisted of 550,000 options issued to employees and directors with exercise prices equal to the fair value of the Company's stock and, in accordance with APB 25 no compensation expense was required to be recorded.

During 2001, the Company's option grants included 30,000 stock options issued to a consultant for services at $1.75 per option, resulting in administrative expense recorded in the U.S. GAAP financial statements of $20,100 in accordance with SFAS 123. The remainder of options issued in 2001 were issued to employees and directors with exercise prices equal to the fair value of the Company's stock and, in accordance with APB 25 no compensation expense was required to be recorded.

During 2000, the Company's option grants consisted of 45,000 options issued to employees and directors with exercise prices equal to the fair value of the Company's stock and, in accordance with APB 25 no compensation expense was required to be recorded.

Prior to 2000, there had been $1,519,021 of compensatory stock options issued in accordance with APB 25.

The Company has adopted the disclosure-only provisions of SFAS 123, "Accounting for Stock-Based Compensation" for stock based awards to employees and directors. Had compensation cost for the Company's stock option plan been determined based on the fair value at the grant date for awards in 2002, 2001 and 2000 consistent with the provisions of SFAS No. 123, the Company's net (loss) earnings would have been decreased to the pro forma amounts indicated below:

	2002 $	2001 $	2000 $
Net (loss) earnings, U.S. basis as reported	**(3,066,085)**	9,116,930	3,933,527
Pro forma net (loss) earnings, U.S. basis under SFAS 123	**(3,229,062)**	8,716,719	3,875,027
(Loss) earnings per share, U.S. basis as reported	**(0.15)**	0.46	0.20
(Loss) earnings per share, U.S. basis under SFAS 123	**(0.16)**	0.44	0.20

The Black-Scholes options valuation model was used to estimate the fair value of trade options, which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. As the Company's employee and director stock options have characteristics different from those of traded options, and changes in the subjective input assumptions can materially affect the fair value estimate, the existing models do not necessarily provide a reliable single measure of the fair value of its employee and director stock options. The fair value of option grants using the Black-Scholes model is estimated on the date of grant using the following weighted-average assumptions:

	2002 $	2001 $	2000 $
Dividend yield	**0%**	0%	0%
Expected volatility	**57%**	48%	88%
Risk-free interest rate	**5%**	6%	5%
Expected lives	**3 years**	3 years	3 years

The weighted average fair value per share of stock options granted during fiscal 2002 is $0.83 [2001 – $0.81; 2000 – $1.30].

[b] Under the successful efforts method of accounting, according to Canadian GAAP, the net carrying cost of oil and gas properties in producing cost centres is limited to an estimated recoverable amount, which is the aggregate of future net operating revenues from proved producing reserves net of certain costs (the "Canadian ceiling test"). Under U.S. GAAP, costs accumulated in each cost centre are limited to an amount equal to the present value, using an annual cash flow discount rate of 10%, of the estimated future net operating revenues from proved producing reserves (the "U.S. ceiling test").

[c] Effective April 1, 1999, the Company adopted the new Canadian GAAP recommendations with respect to income taxes which requires application of the liability method of tax allocation, similar to the requirements under U.S. GAAP. However, there remains a difference between Canadian and U.S. GAAP as Canadian GAAP requires that deferred income tax balances be adjusted to reflect substantively enacted rates rather than the current legislated tax rates under U.S. GAAP.

[d] Share issue costs are charged directly to retained earnings under Canadian GAAP and are charged directly to share capital under U.S. GAAP. The total share issue costs charged to share capital to date at March 31, 2002 and 2001 was $570,961.

12. Commitments

[a] On December 18, 1997, the Company agreed to sell and lease back under an operating lease, for an initial term of five years, its St. Albert gas processing facilities to Enercap Corporation of Calgary, Alberta [note 4]. Under the terms of the agreement, the Company is committed to future lease payments over the one remaining year of the initial term as shown in the table below.

Lease costs pursuant to the leaseback agreement are recorded as production costs.

At the end of the initial period of the leaseback (November 30, 2002), the Company has the option to repurchase the gas processing facilities for $780,000. The Company intends to exercise this option.

[b] The Company has entered into an operating lease in respect of its office premises. Minimum payments under this lease commitment, including estimated operating costs over the next two years are also included in the table below.

	Gas processing facilities $	*Office premises* $
2003	467,811	72,329
2004	–	60,274
	467,811	132,603

13. Economic Dependency

The St. Albert property in Alberta is a core property for the Company and the majority of gas production from the property is pipelined and processed through facilities owned and operated by Atco Midstream ("Atco") of Calgary, Alberta.

Effective November 1, 1997, the Company and its then joint interest partner, Fletcher Challenge Energy Canada Inc. signed a ten-year, firm service, sour gas processing and transportation agreement with Atco for a maximum daily quantity of 15 million cubic feet of gas per day to be processed at Atco's Carbondale plant.

Effective December 15, 1998, a similar agreement was signed by the partners and Atco to process sweet gas at Atco's Villenueve plant, also for a maximum daily quantity of 15 million cubic feet of gas per day.

Both agreements include an automatic renewal for a further ten years, subject to fee re-negotiation.

14. Subsequent Events

Normal course issuer bid

Pursuant to a normal course issuer bid commencing May 1, 2002 and terminating March 31, 2003 or earlier, the Company was authorized to repurchase and cancel up to 1,000,000 common shares on the open market through the facilities of the Toronto Stock Exchange and NASDAQ. To date, there have been no repurchases made.

15. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

SCHEDULE 1

General and Administrative

(in Canadian dollars)

Years ended March 31

	2002 $	2001 $	2000 $
Advertising and promotion	**250,792**	218,880	233,098
Insurance	**122,583**	43,034	40,967
Interest	**98,087**	18,469	16,551
Office and printing	**432,947**	231,490	219,330
Professional fees	**530,203**	402,925	351,673
Provincial capital taxes	**83,062**	37,000	–
Regulatory and other fees	**72,472**	70,219	107,658
Rent	**89,581**	84,646	67,183
Salaries and benefits [1]	**1,086,958**	633,601	572,577
Telephone	**16,423**	13,354	18,406
Travel	**23,054**	20,361	17,167
Cost recoveries	**(458,950)**	(204,804)	(25,789)
	2,347,212	1,569,175	1,618,821

[1] The Company also pays overriding royalties to three officers as described in note 10.

SCHEDULE 2

Amortization and Depletion

(in Canadian dollars)

Years ended March 31

	2002 $	2001 $	2000 $
Amortization and depletion	**12,118,849**	3,132,663	1,644,209
Future removal and site restoration provision	**284,368**	184,925	166,205
Amortization of deferred financing costs	**–**	1,412	6,122
Amortization of deferred gain on sale	**(230,274)**	(312,036)	(352,381)
	12,172,943	3,006,964	1,464,155

SCHEDULE 3

Exploration Expenses

(in Canadian dollars)

Years ended March 31

	2002 $	2001 $	2000 $
Drilling	**3,821,374**	667,684	948,372
Seismic data activity	**649,216**	1,101,969	184,997
Non-producing lease rentals	**64,605**	51,856	28,460
Property investigations	**110,823**	101,685	137,447
	4,646,018	1,923,194	1,299,276

CORPORATE INFORMATION

Directors

Wayne J. Babcock	*Vancouver, British Columbia*
John A. Greig	*Vancouver, British Columbia*
David J. Jennings	*Vancouver, British Columbia*
John Lagadin	*Calgary, Alberta*
Jonathan A. Rubenstein	*Vancouver, British Columbia*
Donald K. Umbach	*Vancouver, British Columbia*

Officers

Wayne J. Babcock	*President and Chief Executive Officer*
Donald K. Umbach	*Vice President and Chief Operating Officer*
James R. Britton	*Vice President, Exploration*
Michael A. Bardell	*Chief Financial Officer and Corporate Secretary*

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Consulting Engineers

Status Engineering Associates Ltd. *Calgary, Alberta*

Solicitors

Irwin, White & Jennings *Vancouver, British Columbia*
Perkins Coie LLP *Santa Monica, California*

Auditors

Ernst & Young LLP *Vancouver, British Columbia*

Bankers

National Bank of Canada *Calgary, Alberta*

Registrar and Transfer Agent

CIBC Mellon Trust Company *Vancouver, British Columbia*

Trading Symbols

TSE : DOL NASDAQ : DYOLF

Capital Stock

Common Outstanding: 20,462,230 to June 30, 2002

Annual Meeting

The Annual General Meeting of the Shareholders will be held in the Fraser Room of the Holiday Inn, 10720 Cambie Road, Richmond, B.C. on Thursday, August 22, 2002 at 1:00pm.

Form 20F

A copy of the Company's latest report on Form 20F, as filed with the Securities and Exchange Commission is available without charge, upon written request to the Corporate Secretary.

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